1 Greendale Drive, Caledonia, ON, N3W 2J3 Tel: (905) 765-5344 Fax: (905) 765-5316

August 28, 2009

Delivered By Courier

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

Attention: Kirsten Walli
Board Secretary

Re: Haldimand County Hydro Inc. (EB-2009-0265)
2010 Electricity Distribution Rate (Cost of Service) Application

Dear Ms. Walli:

Haldimand County Hydro Inc. hereby submits its Cost of Service Rate Application, based on a 2010 forward test year, for Electricity Distribution Rates to be effective May 1, 2010 (the "Application").

This Application is filed in accordance with the Ontario Energy Board's (the "Board's") "*Filing Requirements for Transmission and Distribution Applications*", issued November 14, 2006, including the update to Chapter 2 issued May 27, 2009 and the update to Chapter 3 issued July 22, 2009.

Two hard copies of the Application are now enclosed. An electronic copy of the full application in PDF format and required models in Excel format will be submitted through the Board's *Regulatory Electronic Submission System* ("RESS").

This 2010 Electricity Distribution Rate (Cost of Service) Application is respectfully submitted for the Board's consideration.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by Jacqueline A. Scott

Jacqueline A. Scott
Finance Manager

HALDIMAND COUNTY HYDRO INC.

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2010

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

AND IN THE MATTER OF an Application by Haldimand County Hydro 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, 2010.

Title of Proceeding:	An application by Haldimand County Hydro Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2010.
Applicant's Name:	Haldimand County Hydro Inc.
Applicant's Address for Service:	1 Greendale Drive Caledonia, Ontario N3W 2J3
	Attention: Mr. Lloyd E. Payne, President & CEO
	Telephone: 905-765-5344 Fax: 905-765-5316 E-mail: lpayne@hchydro.ca

APPLICATION

1. Introduction

(a) The Applicant is Haldimand County Hydro Inc. (referred to in this Application as the "Applicant" or "HCHI"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the Town of Caledonia, ON. The Applicant carries on the business of distributing electricity within Haldimand County.

(b) 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, 2010. A list of requested approvals is set out in Exhibit 1, Tab 1, Schedule 5.

(c) 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 May 27, 2009 (the "Filing Requirements") in order to prepare this application.

2. Proposed Distribution Rates and Other Charges

(a) The Schedule of Proposed Tariff of Rates and Charges in this Application is set out in Appendix A attached to this application and Exhibit 8, Tab 1, Schedule 6, and the material being filed in support of this Application sets out HCHI's approach to its distribution rates and charges.

3. Proposed Effective Date of Rate Order

(a) The Applicant requests that the OEB make its Rate Order effective May 1, 2010 in accordance with the Filing Requirements.

4. The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

(i) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

(ii) the proposed adjusted rates are necessary to meet the Applicant's Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILs") requirements;

(iii) 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;

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

(v) such other grounds as may be set out in the material accompanying this Application Summary.

5. Relief Sought

(a) The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 1, Tab 1, Schedule 2, Appendix A to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2010, or as soon as possible thereafter.

6. Form of Hearing Requested

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

DATED at Caledonia, Ontario, this 28th day of August, 2009.

All of which is respectfully submitted,

HALDIMAND COUNTY HYDRO INC.

Lloyd E. Payne
President & CEO

DISTRIBUTOR LICENCE

A copy of Haldimand County Hydro Inc.'s Electricity Distribution Licence ED-2002-0539, issued on October 21, 2003, accompanies this Schedule as Appendix B hereto.

CONTACT INFORMATION

HALDIMAND COUNTY HYDRO INC.
1 Greendale Drive
Caledonia, ON
N3W 2J3

PRESIDENT & CHIEF EXECUTIVE OFFICER:

Mr. Lloyd E. Payne
Telephone: 905-765-5211 ext. 2242
Facsimile: 905-765-5316
E-mail: lpayne@hchydro.ca

FINANCE MANAGER:

Ms. Jacqueline A. Scott
Telephone: 905-765-5211 ext.2237
Facsimile: 905-765-5316
E-mail: jscott@hchydro.ca

SPECIFIC APPROVALS REQUESTED

In this proceeding, HCHI is requesting the following:

- Approval to charge rates effective May 1, 2010 to recover a service revenue requirement of $13,938,976 as set out in Exhibit 8, Tab 1, Schedule 1. The schedule of proposed rates is set out in Exhibit 1, Tab 1, Schedule 2 Appendix A and Exhibit 8, Tab 1, Schedule 6;

- Approval of the Applicant's proposed change in capital structure, decreasing the Applicant's deemed common equity component from 43.3% to 40.0% and increasing the deemed debt component from 56.7% to 60.0%, as set out in Exhibit 5, Tab 1, Schedule 2, consistent with the OEB's "*Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors"* dated December 20, 2006;

- Approval of the proposed loss factor as set out in Exhibit 8, Tab 1, Schedule 4;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of HCHI's 2009 Electricity Distribution Rates (EB-2008-0181);

- Approval of the proposed increase to the Retail Transmission Service Rates, including Network and Connection charges, as a result of an analysis of HCHI's retail transmission service rates variance accounts and the OEB's decision issued July 3, 2009 on Hydro One Networks Inc.'s Transmission Rate Application (OEB File EB-2008-0272) for amended 2009 Uniform Transmission Rates effective July 1, 2009 as set out in Exhibit 8, Tab 1, Schedule 1, to be effective May 1, 2010;

- Approval for HCHI to further adjust the "proposed" Retail Transmission Service Rates for Network Service and Connection charges for all classes, to re-calculate the Low Voltage Charges to customer rate classes and to re-calculate the "new" Distribution Wheeling Service Rate applicable to Embedded Distributor – Hydro One Networks Inc. as a result of an OEB decision on Hydro One Networks Inc.'s 2010 / 2011 Distribution Application (EB-2009-0096) currently before the Board;

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of HCHI's 2009 Electricity Distribution Rates (EB-2008-0181);

- Approval for the continuation of the Norfolk Power Distribution Inc. ("NPI") legacy Embedded Distributor Rate Class, including the legacy Distribution Wheeling Service Rate, proposed Retail Transmission Service Rates and the proposed Loss Factor as revised through this application, effective until December 31, 2010, as set out in Exhibit 8, Tab 1, Schedule 1 and Schedule 4;

- Approval for a new rate class, Embedded Distributor – Hydro One Networks Inc., including a proposed Distribution Wheeling Service Rate, proposed Retail Transmission Service Rates and the proposed Loss Factor effective May 1, 2010, as set out in Exhibit 8 Tab 1 Schedule 1 and Schedule 4;

- Approval of the harmonization of the existing Residential Rate Density Classes, Residential Urban and Residential Suburban, into one Residential Rate Class effective May 1, 2010, as set out in Exhibit 8 Tab 1 Schedule 1;

- Approval of the change to the current fixed / variable distribution revenue proportion and the associated proposed rates for the Residential and G/S < 50 kW rate classes effective May 1, 2010, as set out in Exhibit 8 Tab 1 Schedule 1;

- Approval of HCHI's approach to cost allocation, and the associated proposed adjustments to rates in aligning the revenue to cost ratios, as identified in Exhibit 7 with specific adjustments to rates effective May 1, 2010, as set out in Exhibit 8 Tab 1 Schedule 1;

- Approval to dispose of specific Deferral and Variance Account principal balances as at December 31, 2008 with projected interest to April 30, 2010, and the associated rate riders effective May 1, 2010 for recovery over a one-year period as set out in Exhibit 9, Tab 1, Schedule 3;

- Approval for a utility specific Smart Meter Funding Adder effective May 1, 2010 as set out in Exhibit 9, Tab 2 Schedule 3, effective May 1, 2010; and

- Approval for the recovery of LRAM and SSM amounts through combined Rate riders effective May 1, 2010 for recovery over a one-year period as set out in Exhibit 10, Tab 1, Schedule 2.

PROPOSED ISSUES LIST

The Applicant would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2010 Test Year may constitute issues in this Application:

- The amount of HCHI's proposed revenue requirement;
- The harmonization of the Residential Density Rate Classes, Residential Urban and Residential Suburban, into one new Residential Rate Class;
- The proposal for an adjustment to the current fixed / variable split for the Residential and G/S < 50 kW rate classes;
- The proposal for approval of the applicants utility specific smart meter funding adder;
- The calculation of lost revenue on the Embedded Distributor Rate Class applicable to Norfolk Power Distribution Inc. and the continued use of the legacy Distribution Wheeling Service Rate;
- The reasonableness of the proposed electricity distribution rates, including the new Embedded Distributor rates applicable to Hydro One Networks Inc.; and
- The appropriateness of HCHI's proposed cost allocation-related adjustments to class-specific revenue requirements, reflected in the proposed distribution rates.

PROCEDURAL ORDERS / MOTIONS / NOTICES

On March 12, 2007, the OEB issued its report "*LDC Screening Methodology to Establish a Rebasing Schedule for Electricity LDCs*" (the "Report"). The purpose of the Report was "*to describe the criteria to be considered in determining which electricity distributors to engage in proceedings before the Board for rebasing to establish rates for each of the years 2008, 2009 and 2010*" and to establish the next steps and timelines for filing. Section 3.3 of the Report provided an opportunity for LDCs to "self-nominate" to be rebased in a particular year.

On April 2, 2008, HCHI filed a self-nomination request for rebasing in 2010. Subsequently, in Board File No. EB-2006-0330, the OEB issued its list of distributors that will be rebased in 2010. HCHI was included on that list.

The Board issued a letter dated January 29, 2009 indicating their decision to extend the number of years for rebasing to include 2010 and 2011 rate years. The Board recognized the cost of service process is effort intensive for applicants, the Board and intervenors. Accompany this letter were preliminary lists of electricity distributors selected to rebase in 2010 and 2011 attached as Schedule A and B respectively. On February 9, 2009, HCHI filed a letter of comment confirming they wished to remain scheduled for rate rebasing in 2010. Subsequently, in Board File No. EB-2009-0028, the OEB issued the final list of distributors that will be rebased in 2010 and 2011. HCHI remained on the 2010 list.

ACCOUNTING ORDERS REQUESTED

HCHI is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

HCHI 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") contained therein, in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

Distribution Service Territory

In accordance with HCHI's Electricity Distribution Licence, the Distribution Service area is defined as "*The Corporation of Haldimand County as defined in the Town of Haldimand Act, 1999, excluding the consumer located at 2330 Regional Road 3*".

Haldimand County is located on the north shore of Lake Erie, situated between Norfolk County, Six Nations of the Grand River Territory, County of Brant, City of Hamilton, and Niagara Region.

The total service territory for HCHI is 1,252 km^2, consisting of rural area of 1,216 km^2 and six communities, 36 km^2; Caledonia, Cayuga, Dunnville, Hagersville, Jarvis, and Townsend. The population density of Haldimand County is 36.1 persons per square km based on the County's area and its 18,383 private dwellings, as indicated in the 2006 census. The service area population is represented by the municipal population of 45,212 as indicated in the 2006 census.

A map of the HCHI's Distribution Service Territory accompanies this Schedule as Appendix C.

Distribution System

HCHI owns and operates the electricity distribution system in its licensed service area in Haldimand County, serving approximately 20,843 Residential, General Service, Street Lighting, Sentinel Light and Unmetered Scattered Load customers and two Embedded Distributors, as at June 30, 2009.

HCHI is supplied through the Hydro One Networks Inc. ("HONI") transmission system from 3 transformer stations at a primary voltage of 27.6 kV. Electricity is then distributed through HCHI's service area, 1,252 km^2, over 83 road km of underground cable and 1,570 road km of overhead primary conductor. HONI also owns 87 road km of distribution line in Haldimand County that serves HCHI's customers. Primary voltage

is stepped down through 6 HCHI-owned distribution stations and 2 HONI-owned distribution stations to service General Service and Residential customers. Voltage is stepped down from the 27.6 kV, 8.32 kV, and 4.16 kV primary feeders through approximately 7,229 LDC-owned distribution transformers.

A schematic diagram of HCHI's Distribution System accompanies this schedule as Appendix D.

LIST OF NEIGHBOURING UTILITIES

The following distributors are located adjacent to HCHI's service area:

1. Norfolk Power Distribution Inc.
2. Hydro One Networks Inc.
3. Niagara Peninsula Energy Inc. – Peninsula West

EXPLANATION OF HOST AND EMBEDDED UTILITIES

Haldimand County Hydro Inc ("HCHI") is supplied electricity from Hydro One Networks Inc. ("HONI") through three HONI-owned transformer stations ("TS"), or delivery points, that are registered in the IESO-controlled grid. The three transformer stations are Jarvis TS, Dunnville TS and Caledonia TS.

The feeders connected to each of the transformer stations are of mixed ownership between HONI and HCHI, as identified in the following Table 1.

Table 1
Ownership of Feeders at HONI Transformer Stations

Jarvis TS	Feeder Owner	Caledonia TS	Feeder Owner	Dunnville TS	Feeder Owner
57M1	HCHI	27M3	HONI	31M1	HCHI
57M2	HONI	27M4	HCHI	31M2	HONI
57M3	HONI	27M5	HCHI		
57M4	HCHI	27M6	HONI		
57M5	HCHI				
57M6	HCHI				
57M7	HONI				
57M8	HONI				

Each transformer station supplies electricity to customers that are not part of the HCHI service territory. These situations result in scenarios where HCHI is embedded to HONI, HONI is embedded to HCHI, and Norfolk Power Distribution Inc. ("NPI") is embedded to HCHI. Each scenario will be described in more detail.

HCHI as Host Distributor to NPI

NPI is an embedded distributor to HCHI. Feeder number 57M4 from Jarvis TS is a HCHI owned feeder that supplies electricity to HCHI customers. This feeder also supplies electricity to NPI. At the Haldimand County and Norfolk County boundaries, IESO-registered meter installations were installed in 2001 to measure the electricity used by NPI. The meter points were defined as Highway 6 PMU (ID 1000003580) and

Concession 6 PMU (ID 1000003570). Distribution Wheeling Charge and Retail Transmission Service Rates and Loss Factors were applied for, and approved by the OEB, to be effective on May 1, 2006.

In December 2008, NPI was able to supply electricity to its customers that were connected to the Concession 6 PMU portion of the line from another transformer station within NPI's service territory. The Concession 6 PMU was than de-registered and removed from the Distribution system.

NPI has also indicated in writing that the supply from the 57M4 feeder will not be required after December 31, 2010. When supply from HCHI is not required, Highway 6 PMU will also be de-registered by NPI.

A map depicting NPI Embedded to HCHI accompanies this Schedule as Appendix E.

HCHI as Host Distributor to HONI Scenarios

Scenario 1

HONI has a customer (Air Products) that resides within HCHI's service territory. HONI has requested a second connection or supply for this customer. This second connection is to the HCHI-owned 57M1 feeder connected to Jarvis TS. This connection point is metered with an IESO-registered wholesale meter because Air Products is a Market Participant.

Scenario 2

At Caledonia TS, HONI has de-registered the following meter points from the IESO Wholesale Market.

- 3rd Line PMU
- 4th Line PMU
- 5th Line PMU

- Canadian Gypsum Company PMU
- 6th Line PMU
- Georgia Pacific PMU
- Greens Rd PMU

The electricity that flows through these meter points will be settled using the HCHI retail billing process. Each of the HONI feeders (27M3 and 27M6) has a HCHI owned Wholesale IESO-registered Feeder meter installation. HCHI pays all IESO commodity related charges. HONI is the IESO-transmission connected customer and pays to the IESO all transmission and network connection related charges.

A map depicting HONI Embedded to HCHI accompanies this Schedule as Appendix F.

HCHI as Embedded Distributor to HONI

At Jarvis TS, Caledonia TS and Dunnville TS, HONI and HCHI each own feeders. HCHI has load connected to the following HONI feeders:

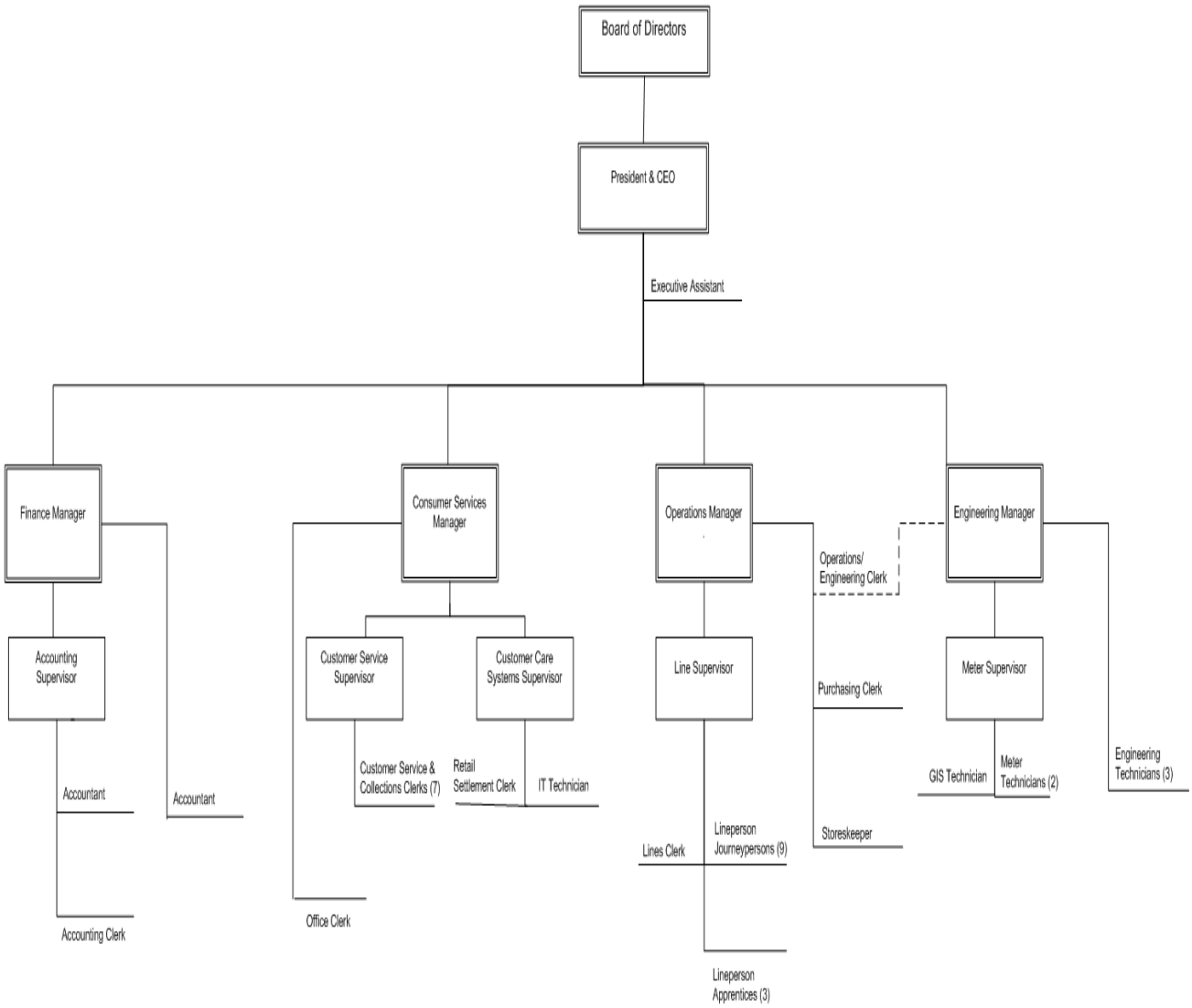
- Jarvis 57M3
- Caledonia 27M3
- Caledonia 27M6
- Dunnville 31M2

The Totalization Tables are set up to calculate the HCHI electricity that flows through these HONI feeders.

A map depicting HCHI Embedded to HONI accompanies this Schedule as Appendix G.

UTILITY ORGANIZATIONAL CHART

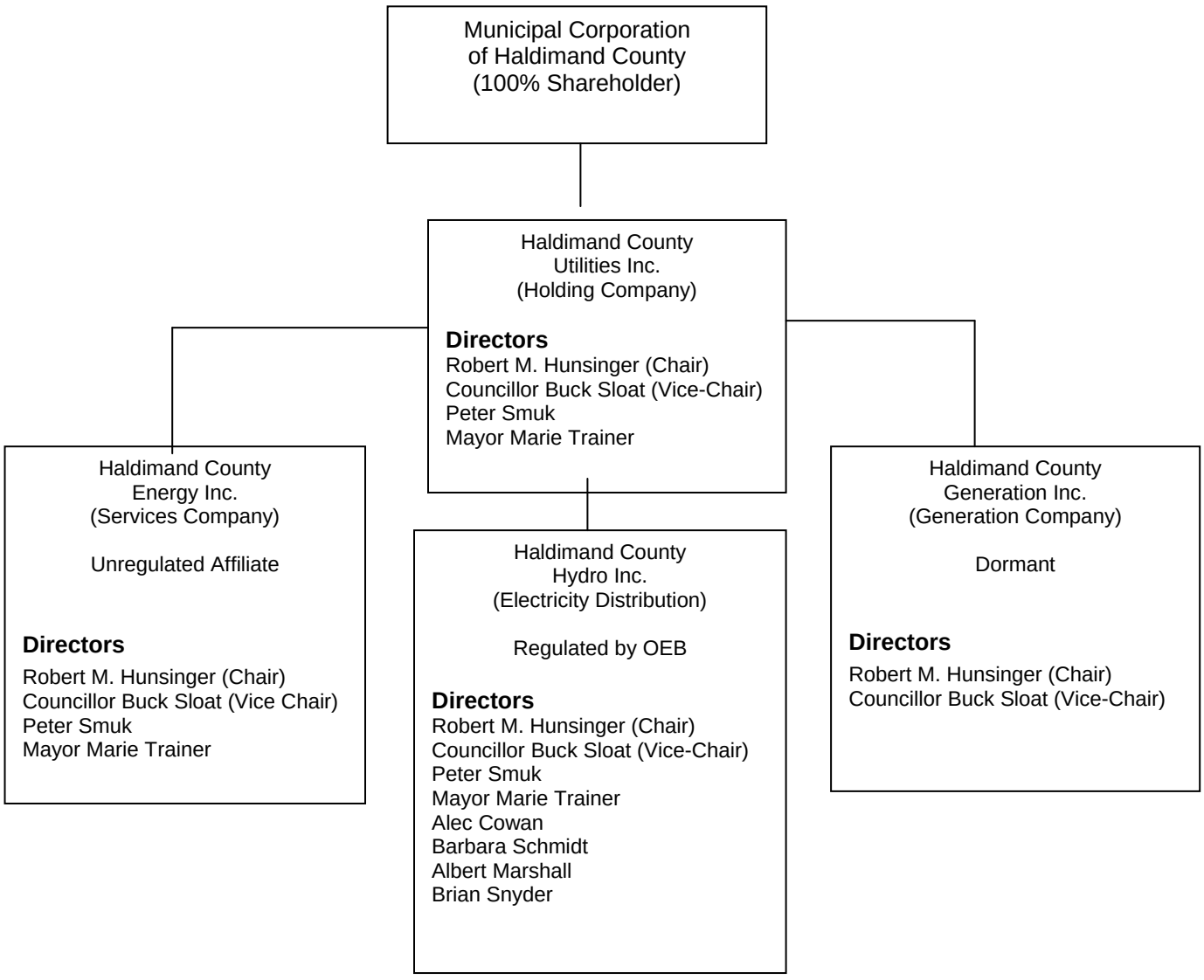
The chart below shows HCHI's existing organizational structure of 46 full-time positions. No changes to this structure are proposed for the 2010 Test Year.



UTILITY ORGANIZATIONAL CHART

HCHI is a wholly-owned subsidiary of Haldimand County Utilities Inc. which is 100% owned by Haldimand County. A chart illustrating HCHI's corporate structure is provided below:

Corporate Structure



Haldimand County Utilities Inc.

Haldimand County Utilities Inc. is a wholly-owned corporation of The Corporation of Haldimand County (the Municipality) and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principal activity of the Company is to act as a Holding Company for the Distribution, Services, and Generation Companies.

Haldimand County Hydro Inc.

Haldimand County Hydro Inc. is a wholly owned subsidiary of Haldimand County Utilities Inc. and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principle activity of the Company is to provide electrical power distribution throughout the Municipality of Haldimand County.

Haldimand County Energy Inc.

Haldimand County Energy Inc. is wholly owned subsidiary of Haldimand County Utilities Inc. and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principle activities of the Company are to provide sentinel light rentals, and water and waste water billing and collecting services for The Corporation of Haldimand County.

Haldimand County Generation Inc.

Haldimand County Generation Inc. is wholly owned subsidiary of Haldimand County Utilities Inc. and was incorporated October 13, 2000 under the laws of the Province of Ontario. The principle activity of the Company is to develop generation projects. Currently, there is no activity in the Company.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

There are no changes planned to HCHI's corporate and operational structures at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS

HCHI does not have any Board directives from a previous Board decision.

CONDITIONS OF SERVICE

A copy of HCHI's latest (current) version of its Conditions of Service (Revision 4.1 at July 10, 2006) was filed separately with the Board on August 14, 2006, and again to the OEB's Compliance Office on June 13, 2007 as requested by the OEB Compliance Office's letter dated June 5, 2007.

PRELIMINARY LIST OF WITNESSES

While HCHI requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary, HCHI will provide a list of potential witnesses as required.

SUMMARY OF THE APPLICATION

HCHI has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Haldimand County Utilities Inc. (HCUI) is the parent company of HCHI. HCHI on its own does not have a specific strategic plan, however, for all practical purposes, HCHI's strategic plan is the same as HCUI.

HCHI's current rates will result in actual Return on Equity in 2009 and 2010 well below levels currently approved by the OEB. The increased rates are required to:

1. Maintain current capital investment levels in infrastructure to ensure a safe, reliable, efficient, and cost effective distribution system;

2. Continue with training programs to ensure health and safety amongst employees and the communities HCHI serves as well as to meet future staffing requirements;

3. Manage staffing levels and skills to ensure regulatory compliance, promote conservation programs, proceed with the full deployment of smart meters, and implement reporting changes resulting from the adoption of International Financial Reporting Standards; and

4. To provide a reasonable rate of return to the Shareholder.

Haldimand County Hydro Inc.'s Corporate Vision and Mission Statements

Vision

To become recognized as a leading participant in the electricity distribution and related businesses sector in Ontario known particularly for high quality service, resilience and adaptability and continuous improvement and efficiency.

Mission

To provide efficient, reliable and safe electricity distribution and other related services to customers and to contribute to the development of our jurisdiction's economy and our employees and the protection of the environment while enhancing the value of Haldimand County Hydro Inc.

Haldimand County Hydro Inc.'s priorities are defined in its Corporate Goals

Present vision and mission statements for the corporation and secure consensus agreement among Management, the Board of Directors, and the Shareholder on the elements of the vision and mission.

Continue to enhance and invest in the quality of the electricity distribution assets.

Expand the electricity distribution business in a prudent and profitable manner.

Develop the depth and capability of our personnel to meet the ongoing needs of our existing and any new businesses.

Execute a series of communications for all stakeholders.

Initiate proactive actions that continue to contribute to the development of the jurisdiction's economy.

Execute actions that will enhance HCHI's ability to meet or exceed the performance based regulation targets set by the Ontario Energy Board and allow HCHI to earn the maximum allowable rate of return.

Investigate and pursue new business opportunities that will enhance shareholder value and bring value added services to customers subject to the restrictions contained in item "3.1 Business of the Corporations" of the Shareholder Direction and Unanimous Shareholder Declaration and section 73. "Municipally-owned distributors" of the Ontario Energy Board Act, 1998.

In keeping with the vision to pursue health and safety as one of HCHI's top priorities, HCHI was recently awarded by the Electrical & Utilities Safety Association ("E&USA") the first step in the ZeroQuest program (the pursuit for zero lost time injuries and illnesses) the Bronze or Commitment Level. To promote public safety, HCHI has initiated health and safety measures that focus on proactive actions. The commitment involves the following; documenting meeting content, safety training, monitoring conformance to established standards and policies, determining the effectiveness of

safety training, implementation of a Risk Analysis Program, monitoring the resolution of safety recommendations / audits, and identifying and correcting the root causes for system deficiencies.

Within its service territory, HCHI has partnered with local agencies and businesses to deliver innovative conservation and demand management programs.

HCHI has consistently exceeded the OEB's Service Quality Indicators ("SQIs") as reported annually on January 31st to the OEB for the previous calendar year. The OEB's *Distribution System Code* ("DSC") was amended June 4, 2008 to implement Electricity Service Quality Requirements ("SQRs"); as Chapter 7, Service Quality Requirements, coming into force January 1, 2009. As set out in Table 1 below, HCHI has targeted to maintain its performance at levels equal to or above the OEB's standards in 2009 and 2010. This table includes the existing customer related SQRs, previously SQIs, as well as the new customer related SQRs; first reporting January 31, 2010 on account of the reporting period January 1 to December 31, 2009.

Table 1
HCHI's Service Quality Requirements
Targeted for 2009 Bridge and 2010 Test Years
(Based on 3-Year Average Performance (2006 – 2008))

Appointments Scheduling – within 5 business days of initial date of request		
SQR Standard: 90% of the time		
3-Year Average	**2009 Target**	**2010 Target**
Not Applicable ("New" SQR January 1, 2009)	90.00%	95.00%
Appointments Met – at the appointed time (Now to include Underground Locates)		
SQR Standard: 90% of the time		
3-Year Average	**2009 Target**	**2010 Target**
97.98% (average of locates & appointments met)	98.00%	99.00%

Rescheduling a Missed Appointment – within 1 business day of initial appointment date		
SQR Standard: 100% of the time		
3-Year Average	**2009 Target**	**2010 Target**
Not Applicable ("New" SQR January 1, 2009)	100.00%	100.00%
Telephone Accessibility – answered in person within 30 seconds		
SQR Standard: 65% of the time		
3-Year Average	**2009 Target**	**2010 Target**
87.31%	88.00%	90.00%
Telephone Call Abandon Rate – calls abandoned prior to answered in person		
SQR Standard: 10% or less		
3-Year Average	**2009 Target**	**2010 Target**
Not Applicable ("New" SQR January 1, 2009)	10.00%	5.00%
Connection of New Services – within 5 working days		
SQR Standard: 90% of the time		
3-Year Average	**2009 Target**	**2010 Target**
92.44%	93.00%	95.00%
Emergency Response – Urban within 60 minutes and Rural within 120 minutes		
SQR Standard: 80% of the time		
3-Year Average	**2009 Target**	**2010 Target**
95.12%	96.00%	98.00%
Written Responses to Inquiries – within 10 working days		
SQR Standard: 80% of the time		
3-Year Average	**2009 Target**	**2010 Target**
97.10%	98.00%	99.00%

HCHI tracks service reliability statistics, including SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and CAIDI (Speed of Power Restoration) including and excluding "Loss of Supply" related incidents. Table 2 below for the statistics that include "Loss of Supply" shows actual

results for the past five years and an average of these five years historical performance. For the section that excludes "Loss of Supply", results are shown for the past three years and an average of these three years historical performance. A distributor that has at least three years of data, at minimum, should remain within the range of their historical performance. ("Loss of Supply" statistics were not separated prior to 2006)

Table 2
HCHI's Service Reliability Indices
(Including Average for Performance Comparisons)

Includes Loss of Supply (Five Years of Statistics – 2004 to 2008)

Index	2004	2005	2006	2007	2008	5-Year Average
SAIDI	3.06	5.81	11.73	10.84	7.10	7.71
SAIFI	1.83	2.48	2.15	3.95	2.63	2.61
CAIDI	1.67	2.34	5.46	2.75	2.70	2.96

Excludes Loss of Supply (Three Years of Statistics – 2006 to 2008)

Index	2004	2005	2006	2007	2008	3-Year Average
SAIDI			3.78	10.24	7.03	7.02
SAIFI			1.55	3.37	2.58	2.50
CAIDI			2.44	3.04	2.72	2.81

In each of 2007 and 2008, HCHI's service reliability statistics were negatively affected by major storms in the month of January. As well in 2008, HCHI experienced multiple summer storms, with heavy rain and high winds that also negatively affected the service

reliability indices. As a result, SAIDI and SAIFI reliability indices increased significantly as compared to prior years. HCHI is committed to the reliability of its distribution system and will continue to make capital investments in infrastructure in order to improve on these reliability indices.

The Application for 2010 Distribution Rates and Charges

HCHI's requested revenue requirement for 2010 in the amount of $13,938,976 includes the recovery of its costs to provide distribution services, recovery of PILs, its permitted Return on Equity ("ROE") and the funds necessary to service its debt as it transitions to a 60% / 40% debt / equity ratio by 2010.

When forecasted energy and demand levels for 2010 are considered, HCHI estimates that its present rates will produce a deficiency in gross distribution revenue of $1,584,943 for the 2010 Test Year. Should this revenue deficiency continue, HCHI will not be able to sustain the current capital investment and training programs required to ensure a safe and reliable distribution system.

Therefore, HCHI 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 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Tab 1, Schedule 6 to this Application.

The information presented in this Application is HCHI's forecasted results for its 2010 Test Year. HCHI is also presenting the OEB with Board-approved data for 2006, the historical actual data for each of 2006, 2007, and 2008, and forecast results for the 2009 Bridge Year.

The financial information supporting the Test Year for this Application will be HCHI's fiscal year ending December 31, 2010 (the "2010 Test Year"). However, this information will be used to set rates for the period May 1, 2010 to April 30, 2014; that is until HCHI expects to prepare its next cost of service rate application in order to rebase

as per the OEB's current Multi-year Electricity Distribution Rate Setting Plan; originally set as a three-year period but extended to a four-year period in the Board Secretary's letter dated January 29, 2009.

Customer Impact

In preparing this application, HCHI has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, HCHI notes that for the majority of its customers, the current revenue to cost ratio of each rate class falls within the applicable threshold defined by the OEB in the November 28, 2007, *Report on Application of Cost Allocation for Electricity Distributors*; with the exception of the Street Lighting and Sentinel Lights rate classes. As a result, an adjustment has been made in this Application to bring the Street Lighting and Sentinel Lights rate classes to 50% of the difference between their current level and the lower boundary of the Board's policy ranges. HCHI will further adjust the revenue-to-cost ratios for these two classes by another 50% in 2011 to bring them to the lower boundary of the approved ranges. Increased distribution revenue from these two classes will be offset by reductions in distribution revenue from the G/S 50 to 4999 kW customer class in each of 2010 and 2011 respectively, which is currently over contributing and hence cross-subsidizing the Street Lighting and Sentinel Light classes.

With regards to cost allocation and the monthly service charge, the G/S 50 to 4999 kW customer rate class current approved monthly service charge has been below the floor amount (avoided costs) as calculated in HCHI's 2007 Cost Allocation Filing (EB-2007-0002) and in the Cost Allocation model updated for 2010. HCHI takes the opportunity with this cost of service rate application to move the G/S 50 to 4999 kW monthly service charge to the calculated ceiling amount generated from the updated 2010 Cost Allocation model. This increase in service charge has not generated a total bill impact greater than 3% due to the overall distribution revenue decrease required from this customer class as presented above.

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 loss factors, deferral and variance account rate riders, LRAM / SSM rate riders, and a utility specific Smart Meter Funding Adder requested as part of this application, and updated Low Voltage Charge Rates and Retail Transmission Service Rates, are set out in Table 3 below.

Table 3
Total Bill Impact

Customer Class **Average Usage per Month**	**Monthly Charge ($)**	**Total Bill Impact (%)**
Residential (Harmonized)	$ 7.85	6.97%
800 kWh		
General Service <50 kW	$ 12.10	4.85%
2,000 kWh		
General Service 50 to 4999 kW (non-interval)	$ 56.71	0.79%
75,000 kWh		
100 kW		
General Service 50 to 4999 kW (interval)	$ (84.71)	(0.33%)
250,000 kWh		
500 kW		
Unmetered Scattered Load	$ 2.01	2.99%
500 kWh		
Street Lighting	$8,959.19	36.40%
2,845 Connections		
200,000 kWh		
535 kW		
Sentinel Lights	$ 8.63	89.22%
1 Connection		
76.70 kWh		
0.21 kW		

Major Issues

HCHI has indentified potential issues to be reviewed in this proceeding in Exhibit 1, Tab 1, Schedule 6 (Proposed Issues List).

Comments

HCHI also offers comments on the following matters affecting distributors:

- **Capital Structure**

  HCHI is requesting a change in its deemed capital structure. Specifically, HCHI is requesting a decrease in the deemed equity ratio from 43.3% to 40.0% consistent with the third and final year of the phase-in of the shift in HCHI's capital structure from 50% to 40% equity as outlined in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors* dated December 20, 2006. In the report, the Board deemed a single capital structure for all local distribution companies for rate-making purposes with a split of 60% debt and 40% equity.

- **Return on Equity**

  HCHI has assumed a return on equity of 8.01% consistent with the *Cost of Capital Parameter Updates for 2009 Cost of Service Applications* issued by the OEB on February 24, 2009. HCHI understands that the OEB will update the return on equity rate in early 2010 for rates effective May 1, 2010. HCHI also understands that the OEB has initiated a proceeding to review its policy regarding the cost of capital and any changes to policy made as a result of this review will apply to the setting of rates for the 2010 rate year; the year HCHI is rebasing.

- **Capital Expenditures**

HCHI continues to develop, manage, and maintain its distribution system equipment in order to provide a safe, reliable, and efficient distribution system in order to meet the demand of new and existing customers in its service territory. This is evident in the projects that HCHI has planned for the 2010 Test Year that will increase reliability, reinforce customer relations, and maintain safety for HCHI's customers as well as staff. The following projects highlight just two of many of the significant projects forecast for 2010:

a) Pole Replacement Program – an annual program to replace all known defective poles to increase reliability by installing a new pole to support the conductors under high load conditions while improving on safety conditions since the risk of an incident also has been reduced with the new pole installation.

b) Lakeshore Road Re-build – Rainham – this project involves replacing 50 to 60 year old assets along the Lake Erie shoreline that are largely installed in rear lots away from the travelled portion of the road, making maintenance and restoration very inefficient and costly. This asset re-development along the lake will improve reliability and restoration time as well as reduce the risk of public safety and the safety of HCHI staff. This project also decreases the risk of an environmental issue due to the deteriorating plant being in so close proximity to the lake making a transformer oil spill a sensitive issue.

- **Operating and Maintenance Costs**

Operating and maintenance costs have been updated for the 2010 Test Year to meet HCHI's 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. The proposed costs for the 2010 Test Year are the result of business planning and work prioritization processes that ensure the most appropriate, cost effective solutions are put into place.

Some of these costs include, but are not limited to, the following:

a) Infrared thermography testing;

b) Pole testing;

c) Substation transformer oil analysis; and

d) Annual tree and line clearing activities.

BUDGET DIRECTIVES

HCHI compiles annual budget information for the three major components of the budgeting process: revenue forecasts, operating, maintenance, and administration ("OM&A") expense forecast and capital budget spending forecasts . This budget information is compiled for both the 2009 Bridge Year and the 2010 Test Year.

Revenue Forecast

HCHI calculated its revenue forecasts from its Distribution Revenue model used for HCHI's internal annual budget process, updated to reflect more recent information. The revenue forecasts are based on volume and existing rates for the 2009 Bridge Year and proposed rates for the 2010 Test Year. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 2 and considers such factors as historical load, weather impacts on load, population trends, customer base growth, and general economic conditions.

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

The OM&A expenses for the 2009 Bridge Year and the 2010 Test Year have been forecast based on previous years' experience, review of operating priorities and requirements and future years' requirements. Each item is reviewed account by account for each of the forecast years with overhead costs allocated based on direct labour costs for budget presentation.

Capital Budget

HCHI prepares an annual capital budget which reflects the costs of individual projects and expenditures for the year ahead. This budget is created by reviewing asset and operational issues experienced in the past and anticipated for the future. General plant requirements are determined either corporately or by specific departmental requirements. In addition to the annual capital budget, a five year forecast details trended costs. The annual budget and five year forecast are approved annually by HCHI's Board of Directors. All proposed capital projects are assessed within the

framework of HCHI's capital budget priority as outlined in the Distribution Asset Management Plan ("DAMP"), Exhibit 2, Tab 3, Schedule 1, Appendix A. The specific capital projects for the actual years 2006 to 2008, the bridge year 2009, and the test year 2010 are discussed in detail in Exhibit 2, Tab 2, Schedule 3 and Tab 3, Schedule 2.

CHANGES IN METHODOLOGY

HCHI is not requesting any changes in methodology in the current proceeding.

CAUSES OF REVENUE DEFICIENCY

HCHI's net revenue deficiency is calculated as $1,093,610 and when grossed up for PILs, the gross revenue deficiency is $1,584,943. HCHI's calculation of its 2010 revenue deficiency is provided in Exhibit 6, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- Increases in OM&A costs including amortization expense from the 2008 Actual Year to the 2010 Test Year as discussed in further detail in Exhibit 4, Tab 1, Schedule 1, Overview, and Exhibit 4 Tab 2 Schedule 1, OM&A Costs; and

- Capital Expenditures in 2009 and 2010 exceeded amortization levels and maintaining a certain level of capital investment resulted in an increased rate base on which the rate of return is calculated. HCHI is committed to ensuring the reliability of the distribution system and will continue to invest in capital infrastructure. Changes in the Rate Base are discussed further in Exhibit 2, Tab 1, Schedule 1, Rate Base, and Exhibit 2 Tab 2 Schedule 1, Gross Assets – Property, Plant and Equipment.

HCHI is committed to meeting its corporate mission and goals of providing a safe and reliable distribution system through prudent investments in capital assets and investing in training and education of staff required to meet the future needs of its customers.

REVENUE REQUIREMENT WORK FORM

Published May 27, 2009 as part of the update by the OEB to *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, HCHI has provided the completed "Application" column of the OEB Revenue Requirement Work Form as part of the 2010 Cost of Service Rate Application included as Appendix H to this Exhibit.

FINANCIAL STATEMENTS – 2006, 2007 and 2008

HCHI's Audited Financial Statements for each of the actual years 2006, 2007 and 2008, accompany this Schedule as Appendix I.

The 2008 Federal T2 Corporate Income Tax Return and the 2008 Ontario CT23 Corporations Tax and Annual Return can be found in Exhibit 4, Tab 3, Schedule 1, Appendix A.

PRO FORMA FINANCIAL STATEMENTS – 2009 AND 2010

HCHI's Pro Forma Financial Statements, including a Balance Sheet and Statement of Income and Retained Earnings, for the 2009 Bridge Year and the 2010 Test Year accompany this Schedule as Appendix J and Appendix K respectively.

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED

There is no variation between the 2006, 2007, and 2008 Audited Financial Statements and the corresponding financial results as filed with the OEB annually, and as such a reconciliation is not required.

PROPOSED ACCOUNTING TREATMENT FOR PROJECTS WITH A PROJECT LIFE CYCLE GREATER THAN ONE YEAR

HCHI does not currently capture the cost of funds on Construction Work in Process ("CWIP") and therefore has not reflected any amounts concerning this practice in this application.

INFORMATION ON PARENT AND SUBSIDIARIES

HCHI is a subsidiary of the parent company Haldimand County Utilities Inc. ("HCUI") which is 100% owned by the Corporation of Haldimand County. The corporate relationship has been described in Exhibit 1, Tab 1, Schedule 14. A copy of HCUI's 2008 Annual Report is included as Appendix L to this schedule.

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APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2010 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2010 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2010 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm.

General Service
General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property.

General Service Less Than 50 kW
This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 kW to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. 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
General Service greater than 1,000 to 5,000 kW interval metered.

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Unmetered Scattered Load
This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum 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, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting
This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting.

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. 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.

Embedded Distributor
This classification applies to Norfolk Power Distribution Inc. ("Norfolk Power") effective until December 31, 2010, and Hydro One Networks Inc., both of which are electricity distributors licensed by the Board and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	20.76
Smart Meter Funding Adder	$	1.87
Distribution Volumetric Rate	$/kWh	0.0240
Low Voltage Cost Rate Adder	$/kWh	0.0005
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0008)
LRAM/SSM Rate Rider – effective until April 30, 2011	$/kWh	0.0022
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	29.37
Smart Meter Funding Adder	$	1.87
Distribution Volumetric Rate	$/kWh	0.0210
Low Voltage Cost Rate Adder	$/kWh	0.0004
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0005)
LRAM/SSM Rate Rider – effective until April 30, 2011	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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General Service 50 to 4,999 kW

Service Charge	$	105.91
Smart Meter Funding Adder	$	1.87
Distribution Volumetric Rate	$/kW	4.9302
Low Voltage Cost Rate Adder	$/kW	0.1825
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kW	(0.1244)
LRAM/SSM Rate Rider – effective until April 30, 2011	$/kW	0.0414
Retail Transmission Rate – Network Service Rate	$/kW	1.8801
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6501
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.9943
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8237
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	20.91
Distribution Volumetric Rate	$/kWh	0.0036
Low Voltage Cost Rate Adder	$/kWh	0.0004
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0019)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	7.39
Distribution Volumetric Rate	$/kW	19.0586
Low Voltage Cost Rate Adder	$/kW	0.1340
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kW	(2.8645)
Retail Transmission Rate – Network Service Rate	$/kW	1.4249
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	3.89
Distribution Volumetric Rate	$/kW	9.9657
Low Voltage Cost Rate Adder	$/kW	0.1312
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kW	(3.1629)
Retail Transmission Rate – Network Service Rate	$/kW	1.4178
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2758
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Embedded Distributor – Norfolk Power – effective until December 31, 2010

Distribution Wheeling Service Rate – Norfolk Power	$/kW	0.6201
Retail Transmission Rate – Network Service Rate – Norfolk Power	$/kW	2.9102
Retail Transmission Rate – Line and Transformation Connection Service Rate – Norfolk Power	$/kW	2.6759

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Embedded Distributor – Hydro One Networks Inc.

Service Charge	$	191.77
Distribution Wheeling Service Rate – Hydro One Networks Inc.	$/kW	0.5610
Retail Transmission Rate – Network Service Rate – Hydro One Networks Inc.	$/kW	2.3200
Retail Transmission Rate – Line and Transformation Connection Service Rate – Hydro One Networks Inc.	$/kW	2.0660

Specific Service Charges

Customer Administration		
Legal letter charge	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - 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
Temporary service install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Bell Canada Pole Rentals	$	18.08
Norfolk Pole Rentals – Billed	$	28.61
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)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0680
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0573
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Embedded Distributor - Norfolk Power – effective until December 31, 2010	1.0442
Total Loss Factor – Embedded Distributor – Hydro One Networks Inc.	1.0305

Ontario

Electricity Distribution Licence

ED-2002-0539

Haldimand County Hydro Inc.

Valid Until
October 20, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 21 2003

Ontario Energy Board	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
26th. Floor	26e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means: Haldimand County Hydro Inc.;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

14 "**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

15 "**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

16 "**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

17 "**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer.

18 ## 2 Interpretation

19 2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day.

20 ## 3 Authorization

21 3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

22 a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

23 b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

24 c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

54

11 Distribution Rates

55

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

56

12 Separation of Business Activities

57

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

58

13 Expansion of Distribution System

59

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

60

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

61

14 Provision of Information to the Board

62

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

63

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

64

15 Restrictions on Provision of Information

65

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

66

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on October 21, 2003 and expire on October 20, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

96

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

97

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

98

1 The Corporation of Haldimand County as defined in the Town of Haldimand Act, 1999, excluding the consumer located at 2330 Regional Road 3.

104

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

105

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

106

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

107

SCHEDULE 3 LIST OF CODE EXEMPTIONS

108

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

109

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

110

APPENDIX A MARKET POWER MITIGATION REBATES

111

1 Definitions and Interpretation

112

In this Licence,

113

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

114

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

115

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

116

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO.

117

2 Information Given to IMO

118

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

119

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

120

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.*

121

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

122 i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

123 ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

124 c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

125 The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

126 For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

127 ## 3 Pass Through of Rebate

128 A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

129 a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

130 b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

131 c embedded distributors to whom the distributor distributes electricity.

132 The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

133 If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

134 "ONTARIO POWER GENERATION INC. rebate"

135 Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

136 Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

137 Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Haldimand County Hydro Inc.
Map of Distribution Service Territory
Exhibit 1
Appendix C

Legend

- Provincial Highway
- Haldimand Highway
- Haldimand Road
- Former Regional Road Number
- Local Road
- County Boundary

NOTES:
* UPDATED FOR DUPLICATE CIVIC ADDRESS PROJECT AUGUST 15TH, 2005

HALDIMAND COUNTY, IT'S EMPLOYEES, OFFICERS AND AGENTS ARE NOT RESPONSIBLE FOR ANY ERRORS, OMISSIONS OR INACCURACIES WHETHER DUE TO THEIR OWN NEGLIGENCE OR OTHERWISE. DO NOT USE FOR OPERATING MAP OR DESIGN PURPOSES. ALL INFORMATION SHOULD BE VERIFIED.

Service Area
1252 square kilometers
483 square miles

4 0 2 4 6 8Miles
4 0 2 4 6 8 10Kilometres

NORTH

County of Brant

City of Hamilton

Regional Municipality of Niagara

Six Nations

New Credit

Norfolk County

Caledonia
Blackheath
Sims Lock Road
Willow Grove
York
Empire
Hartford
Springvale
Hagersville
Cayuga
Canborough
Garnet
Townsend
Jarvis
Decewsville
Nelles Corners
Balmoral
Kohler
Fisherville
Cheapside
Selkirk
Nanticoke
Rainham Centre
Sweet's Corners
South Cayuga
Dunnville
Byng
Attercliffe Station
Moulton Station
Stromness
Lowbanks
Port Maitland
Rock Point
(Mohawk) Gull Island
Mohawk Point
Grant Point
Low Point
Blott Point
Evans Point
Featherstone Point
Hoover Point
Peacock Point
Selkirk Provincial Park
Hickory Beach

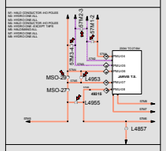
ONEIDA
SENECA
WALPOLE
N. CAYUGA
S. CAYUGA
RAINHAM
DUNN
CANBOROUGH
MOULTON
SHERBROOKE

Grand River
Lake Erie
Oswego Cr.
Sandusky Cr.
Nanticoke Cr.
Sweney Cr.

T:\P&E\DI\P&D\GRAPHICS\COUNTY 911

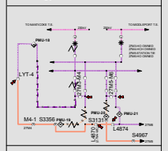
Haldimand County Hydro Inc.
Schematic of Distribution System
Exhibit 1
Appendix D

95 Concession 2, Jarvis



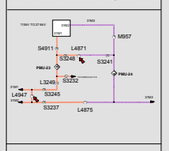
JARVIS T.S.

531 Argyle St. South, Caledonia



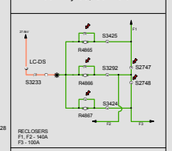
CALEDONIA T.S.

1105 North Shore Drive, Dunnville



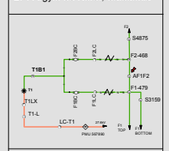
DUNNVILLE T.S.

105 Hwy 56, Canfield



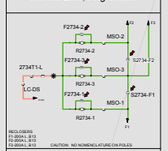
CANFIELD D.S.

271 Argyle St. North, Caledonia



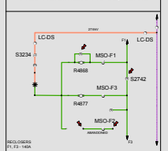
ARGYLE D.S.

168 3rd Line, Hagersville



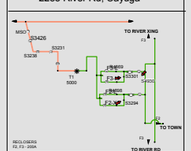
LYTHMORE D.S.

1423 Haldimand Rd 55, Jarvis



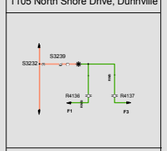
JARVIS D.S.

2283 River Rd, Cayuga



DECEWSVILLE D.S.

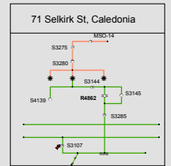
1105 North Shore Drive, Dunnville



DUNNVILLE D.S.

DUNNVILLE - BYNG AREA

71 Selkirk St, Caledonia



SELKIRK 1 D.S.
NORTH STATION

112 Selkirk St, Caledonia

SELKIRK 2 D.S.
SOUTH STATION

Service Area

1252 square kilometers
483 square miles

N

City of Hamilton

County of Brant

Six Nations

Regional Municipality of Niagara

Norfolk County

New Credit

Lake Erie

Featherstone Point

Peacock Point

Evans Point

Low Point

Grant Point

Blott Point

Port Maitland

Mohawk Point

Lowbanks

LEGEND

- 27kV MI FOREIGN OWNED OH PRIMARY
- 8kV 3Ø FOREIGN OWNED OH PRIMARY
- 16kV 1ph OVERHEAD PRIMARY
- 27kV 3ph OVERHEAD PRIMARY
- 16kV 1ph UNDERGROUND PRIMARY
- 4.8kV 1ph OVERHEAD PRIMARY
- 8kV 3ph OVERHEAD PRIMARY
- 4.8kV 1ph UNDERGROUND PRIMARY
- FAULT INDICATOR
- SOLID SWITCH
- AIR BREAK SWITCH
- LOAD BREAK SWITCH
- VOLTAGE REGULATOR
- RABBIT
- FUSED SWITCH, 65 AMPS
- RECLOSER
- CUSTOMER OWNED TRANSFORMER
- MID SPAN OPENERS
- PRIMARY METERING UNIT
- NORMALLY OPEN
- CAPACITOR
- GENERATION POINT
- WIND TURBINE

Haldimand County Distribution			
Haldimand County Hydro	Date: July, 2009	Scale: 1:50,000	
	Drawn by: J.M.G	Approved by:	Rev. No. 6

Haldimand County Hydro Inc.
Map of NPI Embedded to HCHI
Exhibit 1
Appendix E

LOCATION OF REMOVED CONC. 6 PMU (Dec. 2008) ID: 1000003570

JARVIS TS DP#: 105519

From: JARVIS TS 57M4
ID: 1000003580
Name: NORFOLK HWY 6 PMU
Acct#: 122424

Legend

OVERHEAD_PRIMARY

<all other values>

MAP_LAYER, PHASING, VOLTAGE

- HYDRO ONE, B, 16000
- R HH, R, 4800
- W HH, W, 4800
- B HH, B, 4800
- HH, RWB, 8320
- R HH, R, 16000
- W HH, W, 16000
- B HH, B, 16000
- HH, RWB, 27600
- HYDRO ONE, R, 4800
- HYDRO ONE, W, 4800
- HYDRO ONE, B, 4800
- HYDRO ONE, RWB, 8320
- HYDRO ONE, R, 16000
- HYDRO ONE, W, 16000
- HYDRO ONE, RWB, 27600
- HYDRO ONE, RWB, 230000

Norfolk County

NORFOLK HWY 6 PMU

PMU-25

SD01
R0061

57M1
57M2
57M4
57M5
57M6

SUPPLY FROM

NORFOLK 4.8kV SUPPLY FROM

HWY 3
HWY 6
HALDIMAND ROAD 3
HALDIMAND RD 70
HALDIMAND RD 55
LYNN VALLEY RD
RAINHAM RD
RIVERSIDE DR

336 ASC (3/0 ACSR neutral)
336 ASC (1/0 ACSR neutral)
556 ASC (3/0 ACSR neutral)

CONC 6 W-2
CONC 5 W-2
CONC 4 W-1
CONC 3 W-1
CONC 5 W-1

Caution:
By-pass conductor installed

NELSON
AIR PROD
ESM
TNP
ESSO
MOE
MCM
WBR
BWR
RWB

S692-J
S3715
S4642
S4652
S4374
S4837
S0561
S0071
S4825
S4836
S4834
S4203
S3262
S3366
S4951
S4998
S4100
S3413
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S4248
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SAN-1
SAN-2
MSO 22
MSO-30
MSO-33
MSO-09
MOE-7
MOE-2
PMU-10
PMU-11
MSO-13
TNP-1
TNP
44271
DW-1

Haldimand County Hydro Inc.
Map of HONI Embedded to HCHI
Exhibit 1
Appendix F

Legend

OVERHEAD_PRIMARY

<all other values>

MAP_LAYER, PHASING, VOLTAGE

- HYDRO ONE, B, 16000
- HH, R, 4800
- HH, W, 4800
- HH, B, 4800
- HH, RWB, 8320
- HH, R, 16000
- HH, W, 16000
- HH, B, 16000
- HH, RWB, 27600
- HYDRO ONE, R, 4800
- HYDRO ONE, W, 4800
- HYDRO ONE, B, 4800
- HYDRO ONE, RWB, 8320
- HYDRO ONE, R, 16000
- HYDRO ONE, W, 16000
- HYDRO ONE, RWB, 27600
- HYDRO ONE, RWB, 230000

From: HYDRO ONE 27M6
ID: 0245200610
Name: GREENS RD PMU
Acct#: 122732

From: HYDRO ONE 27M6
ID: 0200199360
Name: GEORGIA PACIFIC PMU
Acct#: 122738

ARGYLE DS

From: LYTHMORE DS
ID: 0243200980
Name: 6th LINE PMU
Acct#: 122736

CALEDONIA T.S.
DP#: 105518

From: HYDRO ONE 27M3
ID: 0245200620
Name: 5th LINE PMU
Acct#: 122735

From: LYTHMORE DS
ID: 0245200630
Name: 4th LINE PMU
Acct#: 122734

From: HYDRO ONE 27M3
ID: 0200196420
Name: CANADIAN GYPSUM PMU
Acct#: 122739

From: LYTHMORE DS
ID: 0245200640
Name: 3rd LINE PMU
Acct#: 122733

LYTHMORE DS
27.6kV\8kV

JARVIS T.S.
DP#: 105519

From: JARVIS T.S. 57M1
ID: 1000020870
Name: Hydro One - Air Products PMU
Acct#: 122747

City of Hamilton

Norfolk County

Lake Erie

New Credit

Brantford Nation

Evans Point

Blott Point

Low Point

Featherstone Point

Peacock Point

N

LEGEND

- 27kV 3Ø FOREIGN OWNED O/H PRIMARY
- 8kV 3Ø FOREIGN OWNED O/H PRIMARY
- 16kV 1ph OVERHEAD PRIMARY
- 27kV 3ph OVERHEAD PRIMARY
- 16kV 1ph UNDERGROUND PRIMARY
- 4.8kV 1ph OVERHEAD PRIMARY
- 8kV 3ph OVERHEAD PRIMARY
- 4.8kV 1ph UNDERGROUND PRIMARY
- FAULT INDICATOR
- SOLID SWITCH
- AIR BREAK SWITCH
- LOAD BREAK SWITCH
- VOLTAGE REGULATOR
- RABBIT
- FUSED SWITCH, 65 AMPS
- RECLOSER
- CUSTOMER OWNED TRANSFORMER
- MID SPAN OPENERS
- PRIMARY METERING UNIT
- NORMALLY OPEN
- CAPACITOR
- GENERATION POINT
- WIND TURBINE

Haldimand County Hydro Inc.
Map of HCHI Embedded to HONI
Exhibit 1
Appendix G

N

Circuit - 27M6
ID: 1000016940

Circuit - 27M3
ID: 1000016910

ID: 1000020220
Name: SPRINGVALE PMU

Circuit - 31M2
ID: 1000016880

ID: 1000007570
Name: WAINFLEET PMU

Circuit - 57M3
ID: 1000009410

Service Area
1252 square kilometers
483 square miles

ID 1000016910	27M3	Caledonia T.S.
ID 1000016920	27M4	
ID 1000016930	27M5	
ID 1000016940	27M6	

Denotes HCH owned feeder
Denotes Hydro One owned feeder

ID 1000016870	31M1	Dunnville T.S.
ID 1000016880	31M2	

Denotes HCH owned feeder
Denotes Hydro One owned feeder

ID 1000009380	57M1	Jarvis T.S.
ID 1000009410	57M3	
ID 1000009390	57M4	
ID 1000009420	57M5	
ID 1000009400	57M6	

Denotes HCH owned feeder
Denotes Hydro One owned feeder

LEGEND

- 27kV 3Ø FOREIGN OWNED O/H PRIMARY
- 8kV 3Ø FOREIGN OWNED O/H PRIMARY
- 16kV 1ph OVERHEAD PRIMARY
- 27kV 3ph OVERHEAD PRIMARY
- 16kV 1ph UNDERGROUND PRIMARY
- 4.8kV 1ph OVERHEAD PRIMARY
- 8kV 3ph OVERHEAD PRIMARY
- 4.8kV 1ph UNDERGROUND PRIMARY
- FAULT INDICATOR
- SOLID SWITCH
- AIR BREAK SWITCH
- LOAD BREAK SWITCH
- VOLTAGE REGULATOR
- RABBIT
- FUSED SWITCH, 65 AMPS
- RECLOSER
- CUSTOMER OWNED TRANSFORMER
- MID SPAN OPENERS
- PRIMARY METERING UNIT
- NORMALLY OPEN
- CAPACITOR
- GENERATION POINT
- WIND TURBINE

Haldimand County Distribution			
Haldimand County Hydro	Date: July, 2009	Scale: 1:50,000	
	Drawn by: J.M.G	Approved by:	Rev. No. 6

Lake Erie

REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc. (1)

File Number: EB-2009-0265

Rate Year: 2010 *Version:* *1.0*

Table of Content

Sheet	Name
A	Data Input Sheet
1	Rate Base
2	Utility Income
3	Taxes/PILS
4	Capitalization/Cost of Capital
5	Revenue Sufficiency/Deficiency
6	Revenue Requirement
7	Bill Impacts

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

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REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

Ontario

		Data Input					(1)
		Application		Adjustments		Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$56,508,671	(4)			$56,508,671	
	Accumulated Depreciation (average)	($21,869,118)	(5)			($21,869,118)	
	Allowance for Working Capital:						
	Controllable Expenses	$7,705,417	(6)			$7,705,417	
	Cost of Power	$28,677,930				$28,677,930	
	Working Capital Rate (%)	15.00%				15.00%	
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$11,238,700					
	Distribution Revenue at Proposed Rates	$12,823,644					
	Other Revenue:						
	Specific Service Charges	$212,558					
	Late Payment Charges	$319,125					
	Other Distribution Revenue	$143,153					
	Other Income and Deductions	$440,498					
	Operating Expenses:						
	OM+A Expenses	$7,651,970				$7,651,970	
	Depreciation/Amortization	$2,932,087				$2,932,087	
	Property taxes	$53,447				$53,447	
	Capital taxes	$18,823					
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	$392,023	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$498,787					
	Income taxes (grossed up)	$722,880					
	Capital Taxes	$18,823					
	Federal tax (%)	18.00%					
	Provincial tax (%)	13.00%					
	Income Tax Credits	($21,000)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(2)				(2)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
						Capital Structure must total 100%	
	Cost of Capital						
	Long-term debt Cost Rate (%)	5.58%					
	Short-term debt Cost Rate (%)	1.33%					
	Common Equity Cost Rate (%)	8.01%					
	Prefered Shares Cost Rate (%)						

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(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.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$56,508,671	$ -	$56,508,671
2	Accumulated Depreciation (average)	(3)	($21,869,118)	$ -	($21,869,118)
3	Net Fixed Assets (average)	(3)	$34,639,553	$ -	$34,639,553
4	Allowance for Working Capital	(1)	$5,457,502	$ -	$5,457,502
5	**Total Rate Base**		$40,097,055	$ -	$40,097,055

	(1) Allowance for Working Capital - Derivation				
6	Controllable Expenses		$7,705,417	$ -	$7,705,417
7	Cost of Power		$28,677,930	$ -	$28,677,930
8	Working Capital Base		$36,383,347	$ -	$36,383,347
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$5,457,502	$ -	$5,457,502

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

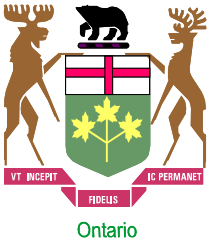
Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

			Utility income		
Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$12,823,644	$ -	$12,823,644
2	Other Revenue	(1)	$1,115,334	$ -	$1,115,334
3	Total Operating Revenues		$13,938,978	$ -	$13,938,978
	Operating Expenses:				
4	OM+A Expenses		$7,651,970	$ -	$7,651,970
5	Depreciation/Amortization		$2,932,087	$ -	$2,932,087
6	Property taxes		$53,447	$ -	$53,447
7	Capital taxes		$18,823	$ -	$18,823
8	Other expense		$ -	$ -	$ -
9	Subtotal		$10,656,327	$ -	$10,656,327
10	Deemed Interest Expense		$1,275,060	$ -	$1,275,060
11	Total Expenses (lines 4 to 10)		$11,931,387	$ -	$11,931,387
12	**Utility income before income taxes**		$2,007,591	$ -	$2,007,591
13	Income taxes (grossed-up)		$722,880	$ -	$722,880
14	**Utility net income**		$1,284,711	$ -	$1,284,711

Notes

(1) Other Revenues / Revenue Offsets

	Application	Adjustments	Per Board Decision
Specific Service Charges	$212,558		$212,558
Late Payment Charges	$319,125		$319,125
Other Distribution Revenue	$143,153		$143,153
Other Income and Deductions	$440,498		$440,498
Total Revenue Offsets	$1,115,334		$1,115,334



REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$1,284,710	$1,284,710
2	Adjustments required to arrive at taxable utility income	$392,023	$392,023
3	Taxable income	$1,676,733	$1,676,733
	Calculation of Utility income Taxes		
4	Income taxes	$498,787	$498,787
5	Capital taxes	$18,823	$18,823
6	Total taxes	$517,610	$517,610
7	Gross-up of Income Taxes	$224,093	$224,093
8	Grossed-up Income Taxes	$722,880	$722,880
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$741,703	$741,703
10	Other tax Credits	($21,000)	($21,000)
	Tax Rates		
11	Federal tax (%)	18.00%	18.00%
12	Provincial tax (%)	13.00%	13.00%
13	Total tax rate (%)	31.00%	31.00%

Notes

REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

Ontario

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$22,454,351	5.58%	$1,253,729
2	Short-term Debt	4.00%	$1,603,882	1.33%	$21,332
3	**Total Debt**	60.00%	$24,058,233	5.30%	$1,275,060
	Equity				
4	Common Equity	40.00%	$16,038,822	8.01%	$1,284,710
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$16,038,822	8.01%	$1,284,710
7	**Total**	100%	$40,097,055	6.38%	$2,559,770
	Per Board Decision				
		(%)	($)	(%)	
	Debt				
8	Long-term Debt	56.00%	$22,454,351	5.58%	$1,253,729
9	Short-term Debt	4.00%	$1,603,882	1.33%	$21,332
10	**Total Debt**	60.00%	$24,058,233	5.30%	$1,275,060
	Equity				
11	Common Equity	40.0%	$16,038,822	8.01%	$1,284,710
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$16,038,822	8.01%	$1,284,710
14	**Total**	100%	$40,097,055	6.38%	$2,559,770

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

Ontario

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$1,584,943		$1,584,943
2	Distribution Revenue	$11,238,700	$11,238,701	$11,238,700	$11,238,701
3	Other Operating Revenue Offsets - net	$1,115,334	$1,115,334	$1,115,334	$1,115,334
4	**Total Revenue**	$12,354,034	$13,938,978	$12,354,034	$13,938,978
5	Operating Expenses	$10,656,327	$10,656,327	$10,656,327	$10,656,327
6	Deemed Interest Expense	$1,275,060	$1,275,060	$1,275,060	$1,275,060
	Total Cost and Expenses	$11,931,387	$11,931,387	$11,931,387	$11,931,387
7	**Utility Income Before Income Taxes**	$422,647	$2,007,591	$422,647	$2,007,591
	Tax Adjustments to Accounting				
8	Income per 2009 PILs	$392,023	$392,023	$392,023	$392,023
9	**Taxable Income**	$814,670	$2,399,614	$814,670	$2,399,614
10	Income Tax Rate	31.00%	31.00%	31.00%	31.00%
11	**Income Tax on Taxable Income**	$252,548	$743,880	$252,548	$743,880
12	**Income Tax Credits**	($21,000)	($21,000)	($21,000)	($21,000)
13	**Utility Net Income**	$191,099	$1,284,711	$191,099	$1,284,711
14	**Utility Rate Base**	$40,097,055	$40,097,055	$40,097,055	$40,097,055
	Deemed Equity Portion of Rate Base	$16,038,822	$16,038,822	$16,038,822	$16,038,822
15	Income/Equity Rate Base (%)	1.19%	8.01%	1.19%	8.01%
16	Target Return - Equity on Rate Base	8.01%	8.01%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-6.82%	0.00%	-6.82%	0.00%
17	Indicated Rate of Return	3.66%	6.38%	3.66%	6.38%
18	Requested Rate of Return on Rate Base	6.38%	6.38%	6.38%	6.38%
19	Sufficiency/Deficiency in Rate of Return	-2.73%	0.00%	-2.73%	0.00%
20	Target Return on Equity	$1,284,710	$1,284,710	$1,284,710	$1,284,710
21	Revenue Sufficiency/Deficiency	$1,093,610	$1	$1,093,610	$1
22	**Gross Revenue Sufficiency/Deficiency**	$1,584,943 **(1)**		$1,584,943 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

Line No.	Particulars	Revenue Requirement	
		Application	Per Board Decision
1	OM&A Expenses	$7,651,970	$7,651,970
2	Amortization/Depreciation	$2,932,087	$2,932,087
3	Property Taxes	$53,447	$53,447
4	Capital Taxes	$18,823	$18,823
5	Income Taxes (Grossed up)	$722,880	$722,880
6	Other Expenses	$ -	$ -
7	Return		
	Deemed Interest Expense	$1,275,060	$1,275,060
	Return on Deemed Equity	$1,284,710	$1,284,710
8	Distribution Revenue Requirement before Revenues	$13,938,977	$13,938,977
9	Distribution revenue	$12,823,644	$12,823,644
10	Other revenue	$1,115,334	$1,115,334
11	**Total revenue**	$13,938,978	$13,938,978
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1 (1)	$1 (1)

Notes

(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2009-0265
Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order								
		Monthly Delivery Charge					Total Bill			
		Current	Per Draft Rate Order	Change $	Change %		Current	Per Draft Rate Order	Change $	Change %
Residential	**800 kWh/month**	$ 44.74	$ 51.59	$ 6.85	15.3%		$ 112.51	$ 120.36	$ 7.85	7.0%
GS < 50kW	**2000** kWh/month	$ 81.79	$ 91.77	$ 9.98	12.2%		$ 249.72	$ 261.82	$ 12.10	4.8%

Notes:

HALDIMAND COUNTY HYDRO INC.

FINANCIAL STATEMENTS

For the year ended December 31, 2006

HALDIMAND COUNTY HYDRO INC.

For the year ended December 31, 2006

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FINANCIAL STATEMENTS	
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Statement of Cash Flows	4
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Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 367, 96 Nelson Street
Brantford, Ontario N3T 5N3
Telephone: (519) 759-3511
Facsimile: (519) 759-7961

AUDITORS' REPORT

To the Shareholder of
Haldimand County Hydro Inc.

We have audited the statement of financial position of Haldimand County Hydro Inc. as at December 31, 2006 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company'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 Haldimand County Hydro Inc. as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

March 1, 2007

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF FINANCIAL POSITION

As at December 31	2006	2005
ASSETS		
Current Assets		
Cash and bank	6,278,593	6,502,427
Unbilled revenue	3,910,946	4,038,124
Accounts receivable	3,319,614	1,800,054
Due from Haldimand County Utilities Inc.	15,905	15,604
Inventory	1,334,216	1,208,504
Income taxes recoverable	-	805,351
Prepaid expenses	158,172	151,791
	15,017,446	14,521,855
Property, Plant and Equipment (Note 4)	31,522,929	30,405,892
Deferred Financing Costs	32,353	42,059
	46,572,728	44,969,806
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	4,853,077	5,472,854
Due to Haldimand County Energy Inc.	294,376	252,425
Income taxes payable	694,632	-
Current portion of long term liabilities	2,178,995	2,367,679
	8,021,080	8,092,958
Regulatory Liabilities (Note 5)	899,547	215,102
Long Term Liabilities (Note 6)	11,702,848	12,507,792
	20,623,475	20,815,852
Deferred Credits		
Contributions in aid of construction	1,961,377	1,607,552
Less: Amortization to date	241,907	171,732
	1,719,470	1,435,820
SHAREHOLDER'S EQUITY		
Capital (Note 7)	19,880,705	19,880,705
Retained Earnings	4,349,078	2,837,429
	24,229,783	22,718,134
	46,572,728	44,969,806

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF INCOME AND RETAINED EARNINGS

For the year ended December 31	2006	2005
Service Revenue		
Residential	13,033,802	12,467,922
General	8,599,819	9,844,902
Street lighting	147,856	133,026
Distribution services	10,543,091	9,011,618
	32,324,568	31,457,468
Service revenue adjustment	(47,245)	(22,395)
	32,277,323	31,435,073
Cost of Power	21,660,295	22,495,462
Gross Margin on Service Revenue	10,617,028	8,939,611
Other Operating Revenue (Note 8)	1,001,457	646,545
	11,618,485	9,586,156
Expenses		
Distribution, operation and maintenance (Note 9)	2,589,695	2,685,337
Community relations	85,931	87,332
Billing and collecting	1,246,221	1,144,673
General Administration	1,682,434	1,505,470
Directors	71,032	63,261
	5,675,313	5,486,073
Amortization	2,096,567	2,292,187
Less: Amortization of contributions in aid of construction	70,175	64,302
	2,026,392	2,227,885
	7,701,705	7,713,958
Income Before Interest and Income Taxes	3,916,780	1,872,198
Interest expense	929,247	968,226
Income Before Income Taxes	2,987,533	903,972
Income taxes - current (Note 10)	1,420,327	747,049
Net Income	1,567,206	156,923
Retained Earnings - Beginning of Year	2,837,429	2,840,547
Dividends	(55,557)	(160,041)
Retained Earnings - End of Year	4,349,078	2,837,429

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF CASH FLOWS

For the year ended December 31	2006	2005
Cash Flows from Operating Activities		
Net Income	1,567,206	156,923
Charges (credits) to income not involving cash		
Amortization	2,096,567	2,292,187
Amortization allocated as overhead	115,869	127,138
Amortization of contributions in aid of capital	(70,175)	(64,302)
(Gain) loss on disposal of property, plant and equipment	(306)	36,727
	3,709,161	2,548,673
Net change in non-cash working capital balances related to operations	(602,617)	(596,694)
	3,106,544	1,951,979
Cash Flows from Financing Activities		
Dividends	(55,557)	(160,041)
Deposits from customers (net)	(88,296)	7,897
Contributions in aid of construction	353,825	536,561
Long term debt	(905,333)	(888,000)
Deferred financing costs	9,706	9,705
	(685,655)	(493,878)
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(3,347,832)	(2,493,616)
Proceeds on disposal of property, plant and equipment	18,664	71,174
Regulatory assets/liabilities	684,445	510,677
	(2,644,723)	(1,911,765)
Net Decrease in Cash and Cash Equivalents	(223,834)	(453,664)
Opening Cash and Cash Equivalents	6,502,427	6,956,091
Closing Cash and Cash Equivalents	6,278,593	6,502,427

See accompanying notes

1. NATURE OF ACTIVITIES

The company was incorporated under the Ontario Business Corporations Act on October 13, 2000 to provide regulated electricity distribution services to residents of Haldimand County.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(b) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(c) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(d) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years
Distribution stations	30 years
Distribution lines - overhead	25 years
Distribution lines - underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Rolling stock	8 years
Other capital assets	5 - 50 years

(e) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Payments in Lieu of Corporate Income Taxes

The Company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Haldimand County Hydro Inc. at that time. As at December 31, 2006, future income tax assets of $765,000, based on substantively enacted tax rates, have not been recorded.

(g) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. The Company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method.

3. RATE SETTING

The rates of the Company's electricity distribution business is subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Haldimand County Hydro Inc. and remitted to the IESO. The Company retains the distribution charge on the customer hydro invoices. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 5.

3. RATE SETTING (continued)

Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2006, were calculated on a 2004 rate base and included a rate of return on equity of 9.0%.

4. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2006	2005
Land	160,824	-	160,824	160,824
Buildings	1,453,274	181,661	1,271,613	1,093,525
Distribution stations	383,067	180,549	202,518	227,169
Distribution lines - overhead	19,865,548	6,121,963	13,743,585	13,424,963
Distribution lines - underground	6,370,747	1,852,931	4,517,816	4,595,536
Distribution transformers	10,267,047	2,487,346	7,779,701	7,303,092
Distribution meters	2,589,470	640,325	1,949,145	1,749,989
Rolling stock	1,144,096	670,358	473,738	436,791
Other capital assets	2,619,629	1,195,640	1,423,989	1,414,003
	44,853,702	13,330,773	31,522,929	30,405,892

5. REGULATORY ASSETS (LIABILITIES)

	2006	2005
Qualifying transition costs	-	938,212
Pre-market opening energy variance	-	710,832
Deferred payments in lieu of taxes	839,393	748,334
Retail settlement variance accounts	(814,887)	(1,313,228)
Recovery of regulatory asset balances	(908,277)	(1,436,242)
Deferred pension costs	187,900	136,990
Smart meters	(37,038)	-
Low voltage services	(166,638)	-
	(899,547)	(215,102)

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On April 12, 2006, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR is to be recovered over a two year period, ending April 2008. The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2004.

5. REGULATORY ASSETS (LIABILITIES) (continued)

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

6. LONG TERM LIABILITIES	**2006**	**2005**
Non-callable debenture, with graduated interest rates starting at 6% in 2000, up to 6.5% in 2010. Interest is payable semi-annually, principal is payable annually. Due May 1, 2010	9,110,000	9,530,000
Non-callable debenture, with graduated interest rates starting at 5.25% in 1999, up to 6.125% in 2009. Interest is payable semi-annually, principal is payable annually. Due July 2, 2009	3,147,000	3,449,000
Prime minus 0.6% CIBC demand loan repayable in monthly instalments of $16,667 plus interest. Due December 2011	1,016,667	1,200,000
Customer Deposits	608,176	696,471
	13,881,843	14,875,471
Current portion	2,178,995	2,367,679
	11,702,848	12,507,792

Estimated annual principal repayments and return of customer deposits are as follows:

2007	-	2,178,995
2008	-	870,069
2009	-	3,050,885
2010	-	7,704,860
2011	-	30,079

The CIBC demand instalment loan is secured by a general security agreement on all property owned by the Company. The debentures are payable to The Corporation of Haldimand County on behalf of the former Region of Haldimand-Norfolk.

7. CAPITAL	2006	2005
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	17,144,796	17,144,796
Miscellaneous Paid-in Capital	2,735,909	2,735,909
	19,880,705	19,880,705

8. OTHER OPERATING REVENUE	2006	2005
Late payment charges	49,129	64,923
Retail service charges	33,734	26,645
Interest earned	60,906	(11,218)
Pole rentals	67,992	(39,377)
Change of occupancy charges	61,556	22,510
Collection charges	239,859	104,553
Reconnection charges	38,077	19,000
Profit on sale of material services	17,134	18,222
Water and sewer billings	323,139	297,849
Gain (loss) on disposal of property, plant and equipment	306	(36,727)
Miscellaneous	109,625	180,165
	1,001,457	646,545

9. DISTRIBUTION OPERATION AND MAINTENANCE	2006	2005
Distribution station equipment	95,191	35,315
Overhead distribution lines	1,408,905	1,560,056
Underground distribution lines	173,477	136,485
Distribution transformers	326,563	328,015
Distribution meters	177,918	163,017
Distribution supervision and engineering	407,641	462,449
	2,589,695	2,685,337

10. INCOME TAXES - CURRENT

	2006	2005
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income before income taxes	2,987,533	903,972
Amortization in excess of Capital Cost Allowance	278,303	606,056
Net change in regulatory assets	684,445	510,677
(Gain) Loss on disposal of assets	(306)	36,727
Other additions and deductions	6,894	5,870
Taxable income	3,956,869	2,063,302
Tax at 35.90%, (2005 - 36.21%)	1,420,327	747,049

11. RELATED PARTY TRANSACTIONS

The company is a wholly owned subsidiary of Haldimand County Utilities Inc. and Haldimand County Utilities Inc. is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. also owns Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

12. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2006, the Company provided prudential support in the form of bank letters of credit of $3,362,596. The letters of credit are secured by a general security agreement on all property owned by the Company.

13. FINANCIAL INSTRUMENTS

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The company's exposure to interest rate risk relates to its floating bank rate indebtedness (see Note 6).

Credit Risk

The company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The risk of significant credit loss is considered remote.

14. COMPARATIVE FIGURES

Certain of the prior year's figures, provided for the purpose of comparison, have been reclassified to conform to the current year's statement presentation.

15. LATE PAYMENT PENALTIES

A class action claiming $500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against The Toronto Hydro-Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

This claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Municipal Electric Association has undertaken a defence of this class action. The action has net yet been certified as a class action and discoveries have not been held. To date, no formal steps have been taken to move the action forward. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the company, consequently no provision for a loss, if any, has been recorded in these financial statements.

HALDIMAND COUNTY HYDRO INC.

FINANCIAL STATEMENTS

For the year ended December 31, 2007

HALDIMAND COUNTY HYDRO INC.

For the year ended December 31, 2007

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Chartered Accountants
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Brantford, Ontario N3T 5N3
Telephone: (519) 759-3511
Facsimile: (519) 759-7961

AUDITORS' REPORT

To the Shareholder of
Haldimand County Hydro Inc.

We have audited the statement of financial position of Haldimand County Hydro Inc. as at December 31, 2007 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company'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 Haldimand County Hydro Inc. as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

March 4, 2008

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF FINANCIAL POSITION

As at December 31	2007	2006
ASSETS		
Current Assets		
Cash and bank	5,335,328	6,278,593
Unbilled revenue	3,952,354	3,910,946
Accounts receivable	2,306,307	3,319,614
OPA conservation program	92,366	-
Due from Haldimand County Utilities Inc.	5,089	15,905
Inventory	1,328,030	1,334,216
Income taxes recoverable	549,534	-
Prepaid expenses	62,221	158,172
	13,631,229	15,017,446
Property, Plant and Equipment (Note 4)	32,534,175	31,522,929
Deferred Financing Costs	22,647	32,353
	46,188,051	46,572,728
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	4,970,677	4,853,077
Due to Haldimand County Energy Inc.	368,452	294,376
Income taxes payable	-	694,632
Current portion of long term liabilities	2,002,905	2,178,995
	7,342,034	8,021,080
Regulatory Liabilities (Note 5)	480,776	899,547
Long Term Liabilities (Note 6)	10,702,459	11,702,848
	18,525,269	20,623,475
Deferred Credits		
Contributions in aid of construction	2,434,207	1,961,377
Less: Amortization to date	326,089	241,907
	2,108,118	1,719,470
SHAREHOLDER'S EQUITY		
Capital (Note 7)	19,880,705	19,880,705
Retained Earnings	5,673,959	4,349,078
	25,554,664	24,229,783
	46,188,051	46,572,728

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF INCOME AND RETAINED EARNINGS

For the year ended December 31	2007	2006
Service Revenue		
Residential	12,861,238	13,033,802
General	8,277,577	8,599,819
Street lighting	151,591	147,856
Distribution services	11,862,512	10,543,091
	33,152,918	32,324,568
Service revenue adjustment	286,649	(47,245)
	33,439,567	32,277,323
Cost of Power	21,648,469	21,660,295
Gross Margin on Service Revenue	11,791,098	10,617,028
Other Operating Revenue (Note 8)	1,098,100	1,001,457
	12,889,198	11,618,485
Expenses		
Distribution, operation and maintenance (Note 9)	4,049,609	2,589,695
Community relations	123,846	85,931
Billing and collecting	1,278,655	1,246,221
General Administration	1,717,554	1,682,434
Directors	76,167	71,032
	7,245,831	5,675,313
Amortization	2,246,550	2,096,567
Less: Amortization of contributions in aid of construction	84,182	70,175
	2,162,368	2,026,392
	9,408,199	7,701,705
Income Before Interest and Income Taxes	3,480,999	3,916,780
Interest expense	878,326	929,247
Income Before Income Taxes	2,602,673	2,987,533
Income taxes - current (Note 10)	873,340	1,420,327
Net Income	1,729,333	1,567,206
Retained Earnings - Beginning of Year	4,349,078	2,837,429
Dividends	(404,452)	(55,557)
Retained Earnings - End of Year	5,673,959	4,349,078

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF CASH FLOWS

For the year ended December 31	2007	2006
Cash Flows from Operating Activities		
Net Income	1,729,333	1,567,206
Charges (credits) to income not involving cash		
Amortization	2,246,550	2,096,567
Amortization allocated as overhead	120,219	115,869
Amortization of contributions in aid of capital	(84,182)	(70,175)
(Gain) loss on disposal of property, plant and equipment	(3,317)	(306)
	4,008,603	3,709,161
Net change in non-cash working capital balances related to operations	(60,004)	(602,617)
	3,948,599	3,106,544
Cash Flows from Financing Activities		
Dividends	(404,452)	(55,557)
Deposits from customers (net)	(188,812)	(88,296)
Contributions in aid of construction	472,830	353,825
Long term debt	(987,667)	(905,333)
Deferred financing costs	9,706	9,706
	(1,098,395)	(685,655)
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(3,381,315)	(3,347,832)
Proceeds on disposal of property, plant and equipment	6,617	18,664
Regulatory assets/liabilities	(418,771)	684,445
	(3,793,469)	(2,644,723)
Net Decrease in Cash and Cash Equivalents	(943,265)	(223,834)
Opening Cash and Cash Equivalents	6,278,593	6,502,427
Closing Cash and Cash Equivalents	5,335,328	6,278,593

See accompanying notes

1. NATURE OF ACTIVITIES

The company was incorporated under the Ontario Business Corporations Act on October 13, 2000 to provide regulated electricity distribution services to residents of Haldimand County.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(b) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(c) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(d) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years
Distribution stations	30 years
Distribution lines - overhead	25 years
Distribution lines - underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Rolling stock	8 years
Other capital assets	5 - 50 years

(e) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Payments in Lieu of Corporate Income Taxes

The Company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Haldimand County Hydro Inc. at that time. As at December 31, 2007, future income tax assets of $1,111,000, based on substantively enacted tax rates, have not been recorded.

(g) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. The Company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method.

3. RATE SETTING

The rates of the Company's electricity distribution business is subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Haldimand County Hydro Inc. and remitted to the IESO. The Company retains the distribution charge on the customer hydro invoices. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 5.

3. RATE SETTING (continued)

Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2007, were calculated on a 2004 rate base and included a rate of return on equity of 9.0%.

4. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2007	2006
Land	160,824	-	160,824	160,824
Buildings	1,910,131	223,064	1,687,067	1,271,613
Distribution stations	383,067	197,352	185,715	202,518
Distribution lines - overhead	21,052,655	7,123,027	13,929,628	13,743,585
Distribution lines - underground	6,735,694	2,150,696	4,584,998	4,517,816
Distribution transformers	10,946,956	2,933,870	8,013,086	7,779,701
Distribution meters	2,660,648	745,353	1,915,295	1,949,145
Rolling stock	1,191,332	777,195	414,137	473,738
Other capital assets	3,121,518	1,478,093	1,643,425	1,423,989
	48,162,825	15,628,650	32,534,175	31,522,929

5. REGULATORY ASSETS (LIABILITIES)

	2007	2006
Deferred payments in lieu of taxes	875,656	839,393
Retail settlement variance accounts	(925,322)	(814,887)
Recovery of regulatory asset balances	(347,219)	(908,277)
Deferred pension costs	196,330	187,900
Smart meters	(12,268)	(37,038)
Low voltage services	(267,953)	(166,638)
	(480,776)	(899,547)

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On April 12, 2006, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR is to be recovered over a two year period, ending April 2008. The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2004.

5. REGULATORY ASSETS (LIABILITIES) (continued)

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

6. LONG TERM LIABILITIES	**2007**	**2006**
Non-callable debenture, with graduated interest rates starting at 6% in 2000, up to 6.5% in 2010. Interest is payable semi-annually, principal is payable annually. Due May 1, 2010	8,660,000	9,110,000
Non-callable debenture, with graduated interest rates starting at 5.25% in 1999, up to 6.125% in 2009. Interest is payable semi-annually, principal is payable annually. Due July 2, 2009	2,826,000	3,147,000
Prime minus 0.6% CIBC demand loan repayable in monthly instalments of $16,667 plus interest. Due December 2011	800,000	1,016,667
Customer Deposits	419,364	608,176
	12,705,364	13,881,843
Current portion	2,002,905	2,178,995
	10,702,459	11,702,848

Estimated annual principal repayments and return of customer deposits are as follows:

2008	-	2,202,905
2009	-	3,041,654
2010	-	7,698,016
2011	-	30,901
2012	-	29,030

The CIBC demand instalment loan is secured by a general security agreement on all property owned by the Company. The debentures are payable to The Corporation of Haldimand County on behalf of the former Region of Haldimand-Norfolk.

7. CAPITAL

	2007	2006
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	17,144,796	17,144,796
Miscellaneous Paid-in Capital	2,735,909	2,735,909
	19,880,705	19,880,705

8. OTHER OPERATING REVENUE

	2007	2006
Late payment charges	61,049	49,129
Retail service charges	38,068	33,734
Interest earned	116,948	60,906
Pole rentals	69,495	67,992
Change of occupancy charges	80,540	61,556
Collection charges	221,142	239,859
Reconnection charges	65,290	38,077
Profit on sale of material services	23,761	17,134
Water and sewer billings	342,267	323,139
Gain (loss) on disposal of property, plant and equipment	3,317	306
Miscellaneous	76,223	109,625
	1,098,100	1,001,457

9. DISTRIBUTION OPERATION AND MAINTENANCE

	2007	2006
Distribution station equipment	239,442	95,191
Overhead distribution lines	2,565,730	1,408,905
Underground distribution lines	138,549	173,477
Distribution transformers	438,060	326,563
Distribution meters	220,067	177,918
Distribution supervision and engineering	447,761	407,641
	4,049,609	2,589,695

10. INCOME TAXES - CURRENT

	2007	2006
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income before income taxes	2,602,673	2,987,533
Amortization in excess of Capital Cost Allowance	268,765	278,303
Net change in regulatory assets	(418,771)	684,445
(Gain) Loss on disposal of assets	(3,317)	(306)
Other additions and deductions	7,821	6,894
Taxable income	2,457,171	3,956,869
Tax at 35.54%, (2006 - 35.90%)	873,340	1,420,327

11. RELATED PARTY TRANSACTIONS

The company is a wholly owned subsidiary of Haldimand County Utilities Inc. and Haldimand County Utilities Inc. is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. also owns Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

12. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2007, the Company provided prudential support in the form of bank letters of credit of $2,115,330. The letters of credit are secured by a general security agreement on all property owned by the Company.

13. FINANCIAL INSTRUMENTS

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The company's exposure to interest rate risk relates to its floating bank rate indebtedness (see Note 6).

Credit Risk

The company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The risk of significant credit loss is considered remote.

14. LATE PAYMENT PENALTIES

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 proceedings 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 and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the Ontario Energy Board ("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. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the company, consequently no provision for a loss, if any, has been recorded in these financial statements.

HALDIMAND COUNTY HYDRO INC.

FINANCIAL STATEMENTS

For the year ended December 31, 2008

HALDIMAND COUNTY HYDRO INC.

For the year ended December 31, 2008

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Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 367, 96 Nelson Street
Brantford, Ontario N3T 5N3
Telephone: (519) 759-3511
Facsimile: (519) 759-7961

AUDITORS' REPORT

To the Shareholder of
Haldimand County Hydro Inc.

We have audited the statement of financial position of Haldimand County Hydro Inc. as at December 31, 2008 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company'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 Haldimand County Hydro Inc. as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

March 3, 2009

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF FINANCIAL POSITION

As at December 31	2008	2007
ASSETS		
Current Assets		
Cash and bank	3,541,338	5,335,328
Unbilled revenue	4,062,384	3,952,354
Accounts receivable	2,788,626	2,306,307
OPA conservation program	-	92,366
Due from Haldimand County Utilities Inc.	-	5,089
Inventory	918,765	1,328,030
Income taxes recoverable	198,740	549,534
Prepaid expenses	284,201	62,221
	11,794,054	13,631,229
Property, Plant and Equipment (Note 5)	35,083,545	32,534,175
Deferred Financing Costs	12,941	22,647
Regulatory Assets (Note 6)	728,070	-
Future Tax Asset	720,465	-
	48,339,075	46,188,051
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	5,565,671	4,970,677
OPA conservation program	45,133	-
Due to Haldimand County Energy Inc.	422,448	368,452
Due to Haldimand County Utilities Inc.	527	-
Current portion of long term liabilities	3,840,829	2,002,905
	9,874,608	7,342,034
Regulatory Liabilities (Note 6)	-	480,776
Long Term Liabilities (Note 7)	7,860,738	10,702,459
	17,735,346	18,525,269
Deferred Credits		
Contributions in aid of construction	2,676,419	2,434,207
Less: Amortization to date	427,196	326,089
	2,249,223	2,108,118
SHAREHOLDER'S EQUITY		
Capital (Note 8)	19,880,705	19,880,705
Retained Earnings (Page 3)	8,473,801	5,673,959
	28,354,506	25,554,664
	48,339,075	46,188,051

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2008	2007
Retained Earnings - Beginning of Year	5,673,959	4,349,078
Adjustment for future income taxes (Note 3)	1,256,318	-
Retained Earnings - Adjusted	6,930,277	4,349,078
Net income	1,993,151	1,729,333
Dividends	(449,627)	(404,452)
Retained Earnings - End of Year	8,473,801	5,673,959

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF INCOME

For the year ended December 31	2008	2007
Service Revenue		
Residential	11,979,437	12,861,238
General	8,216,593	8,277,577
Street lighting	146,066	151,591
Distribution services	11,651,675	11,862,512
	31,993,771	33,152,918
Service revenue adjustment	431,294	286,649
	32,425,065	33,439,567
Cost of Power	20,838,308	21,648,469
Gross Margin on Service Revenue	11,586,757	11,791,098
Other Operating Revenue (Note 9)	2,071,834	1,098,100
	13,658,591	12,889,198
Expenses		
Distribution, operation and maintenance (Note 10)	3,882,465	4,049,609
Community relations	38,718	123,846
Billing and collecting	1,305,776	1,278,655
General administration	1,843,861	1,717,554
Directors	67,824	76,167
	7,138,644	7,245,831
Amortization	2,543,407	2,246,550
Less: Amortization of contributions in aid of construction	101,107	84,182
	2,442,300	2,162,368
	9,580,944	9,408,199
Income Before Interest and Income Taxes	4,077,647	3,480,999
Interest expense	792,201	878,326
Income Before Income Taxes	3,285,446	2,602,673
Income taxes - current (Note 11)	756,442	873,340
- future	535,853	-
	1,292,295	873,340
Net Income	1,993,151	1,729,333

See accompanying notes

HALDIMAND COUNTY HYDRO INC.

STATEMENT OF CASH FLOWS

For the year ended December 31	2008	2007
Cash Flows from Operating Activities		
Net Income	1,993,151	1,729,333
Charges (credits) to income not involving cash		
Amortization	2,543,407	2,246,550
Amortization allocated as overhead	-	120,219
Amortization of contributions in aid of capital	(101,107)	(84,182)
(Gain) loss on disposal of property, plant and equipment	(23,778)	(3,317)
Future income taxes	535,853	-
	4,947,526	4,008,603
Net change in non-cash working capital balances related to operations	737,835	(60,004)
	5,685,361	3,948,599
Cash Flows from Financing Activities		
Dividends	(449,627)	(404,452)
Deposits from customers (net)	17,203	(188,812)
Contributions in aid of construction	242,212	472,830
Long term debt	(1,021,000)	(987,667)
Deferred financing costs	9,706	9,706
	(1,201,506)	(1,098,395)
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(5,125,175)	(3,381,315)
Proceeds on disposal of property, plant and equipment	56,176	6,617
Regulatory assets/liabilities	(1,208,846)	(418,771)
	(6,277,845)	(3,793,469)
Net Decrease in Cash and Cash Equivalents	(1,793,990)	(943,265)
Opening Cash and Cash Equivalents	5,335,328	6,278,593
Closing Cash and Cash Equivalents	3,541,338	5,335,328

See accompanying notes

1. NATURE OF ACTIVITIES

Haldimand County Hydro Inc. ("the Company") was incorporated under the Ontario Business Corporations Act on October 13, 2000 to provide regulated electricity distribution services to residents of Haldimand County.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(b) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(c) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(d) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years
Distribution stations	30 years
Distribution lines - overhead	25 years
Distribution lines - underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Rolling stock	8 years
Other capital assets	5 - 50 years

(e) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Revenue Recognition

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

(g) Payments in Lieu of Income Taxes (PILs)

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

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

(h) Financial Instruments

Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows:

(1) - Cash and bank are classified as Held for Trading and measured at fair value.
(2) - Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method.
(3) - Accounts Payable, amounts due to affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.
(4) - Purchases and sales of financial instruments are accounted for at the trade date.
(5) - Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of CICA Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

(i) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. CHANGE IN ACCOUNTING POLICIES

On January 1, 2008 the Company adopted the following new Canadian Institute of Chartered Accountants (CICA) Handbook Sections: Section 1535 "Capital Disclosures" and Section 3031 "Inventories".

Section 1535 requires the Company to disclose information about its capital and how it is managed. It requires the disclosure of qualitative and quantitative information about the company's objectives, policies and processes for managing capital and whether the Company has complied with any externally imposed capital requirements.

Section 3031 replaced the previous Inventory Section and established revised standards for the measurement of inventory, allocation of overhead, accounting for impairment in inventory value and financial statement disclosure.

There was no effect on the comparative financial statements as a result of adopting these new standards.

On January 1, 2008 the Company adopted the policy of recording future income taxes, converting from the taxes payable method previously used. This change in policy was recorded prospectively without an adjustment to prior year's figures.

Future Accounting Changes

In 2008, the Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. The Company is actively monitoring the transition to IFRS and is analyzing the impact that IFRS will have on its financial statements.

The AcSB has removed a temporary exemption in the CICA handbook Section 1100 "Generally Accepted Accounting Principles" which permits the recognition and measurement of assets and liabilities arising from rate regulation. The CICA has issued an accounting guideline (AcG-19) to provide guidance for rate regulated enitities. This change will be effective relating to fiscal years beginning on or after January 1, 2009. The Company is continuing to assess and monitor any additional implications on its financial statements.

4. RATE SETTING

The rates of the company’s electricity distribution business is subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Haldimand County Hydro Inc. and remitted to the IESO. The Company retains the distribution charge on the customer hydro invoices.

4. RATE SETTING (continued)

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 6. Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2008, were calculated on a 2004 rate base and included a rate of return on equity of 9.0%.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2008	2007
Land	139,071	-	139,071	160,824
Buildings	1,993,907	270,056	1,723,851	1,687,067
Distribution stations	580,903	211,925	368,978	185,715
Distribution lines - overhead	23,707,543	8,209,698	15,497,845	13,929,628
Distribution lines - underground	6,941,095	2,465,472	4,475,623	4,584,999
Distribution transformers	11,961,649	3,366,958	8,594,691	8,013,086
Distribution meters	2,744,748	850,198	1,894,550	1,915,295
Rolling stock	1,185,427	841,028	344,399	414,137
Other capital assets	3,845,497	1,800,960	2,044,537	1,643,424
	53,099,840	18,016,295	35,083,545	32,534,175

6. REGULATORY ASSETS (LIABILITIES)

	2008	2007
Deferred payments in lieu of taxes	985,885	875,656
Retail settlement variance accounts	16,708	(925,322)
Recovery of regulatory asset balances	(138,483)	(347,219)
Deferred pension costs	203,428	196,330
Smart meters	(36,956)	(12,268)
Low voltage services	(302,512)	(267,953)
	728,070	(480,776)

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

6. REGULATORY ASSETS (LIABILITIES) (continued)

On April 12, 2006, the OEB announced its decision regarding the company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2004.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

7. LONG TERM LIABILITIES	**2008**	**2007**
Non-callable debenture, with graduated interest rates starting at 6% in 2000, up to 6.5% in 2010. Interest is payable semi-annually, principal is payable annually. Due May 1, 2010	8,180,000	8,660,000
Non-callable debenture, with graduated interest rates starting at 5.25% in 1999, up to 6.125% in 2009. Interest is payable semi-annually, principal is payable annually. Due July 2, 2009	2,485,000	2,826,000
Prime minus 0.6% CIBC demand loan repayable in monthly instalments of $16,667 plus interest. Due December 2011	600,000	800,000
Customer Deposits	436,567	419,364
	11,701,567	12,705,364
Current portion	3,840,829	2,002,905
	7,860,738	10,702,459

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2009	-	3,440,829
2010	-	7,895,884
2011	-	229,184
2012	-	25,376
2013	-	53,223

The CIBC demand instalment loan is secured by a general security agreement on all property owned by the Company. The debentures are payable to The Corporation of Haldimand County on behalf of the former Region of Haldimand-Norfolk.

8. CAPITAL	2008	2007
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	17,144,796	17,144,796
Miscellaneous Paid-in Capital	2,735,909	2,735,909
	19,880,705	19,880,705

9. OTHER OPERATING REVENUE	2008	2007
Late payment charges	55,173	61,049
Retail service charges	32,359	38,068
Interest earned	1,038,471	116,948
Pole rentals	72,444	69,495
Change of occupancy charges	71,550	80,540
Collection charges	237,270	221,142
Reconnection charges	56,945	65,290
Profit on sale of material services	13,868	23,761
Water and sewer billings	355,829	342,267
Gain (loss) on disposal of property, plant and equipment	23,778	3,317
Ontario Power Authority CDM fees	32,680	-
Miscellaneous	81,467	76,223
	2,071,834	1,098,100

10. DISTRIBUTION, OPERATION AND MAINTENANCE	2008	2007
Distribution station equipment	260,124	239,442
Overhead distribution lines	2,257,635	2,565,730
Underground distribution lines	224,703	138,549
Distribution transformers	346,170	438,060
Distribution meters	244,482	220,067
Distribution supervision and engineering	549,351	447,761
	3,882,465	4,049,609

11. INCOME TAXES - CURRENT

	2008	2007
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income before income taxes	3,285,446	2,602,673
Amortization in excess of Capital Cost Allowance	184,918	268,765
Net change in regulatory assets	(1,208,846)	(418,771)
(Gain) Loss on disposal of assets	(23,778)	(3,317)
Other additions and deductions	46,824	7,821
Taxable income	2,284,564	2,457,171
Tax at 33.11%, (2007 - 35.54%)	756,442	873,340

12. RELATED PARTY TRANSACTIONS

The Company is a wholly owned subsidiary of Haldimand County Utilities Inc. and Haldimand County Utilities Inc. is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. also owns Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

13. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2008, the Company provided prudential support in the form of bank letters of credit of $2,115,330. The letters of credit are secured by a general security agreement on all property owned by the Company.

14. CAPITAL MANAGEMENT

The company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The company's total capital as at December 31, consists of:

	2008	2007
Total long term liabilities	11,701,567	12,705,364
Less: cash and bank	3,541,338	5,335,328
Net long term liabilities	8,160,229	7,370,036
Total shareholder's equity	28,354,506	25,554,664
Total capital	36,514,735	32,924,700

15. FINANCIAL INSTRUMENTS

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The company's exposure to interest rate risk relates to its floating bank rate indebtedness (see Note 7).

Credit Risk

The company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers in accordance with direction provided by the OEB. The Company held deposits of $436,567 at year end in order to mitigate credit risk.

16. CONTINGENCIES

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 proceedings 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 and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the Ontario Energy Board ("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. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

Other
A claim has been filed against the Company for recovery of a claim filed against the former Ontario Hydro. The claim related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

HALDIMAND COUNTY HYDRO INC.
2009 BALANCE SHEET

Account Description	Total
Current Assets	
1005-Cash	5,762,400.34
1010-Cash Advances and Working Funds	-
1020-Interest Special Deposits	-
1030-Dividend Special Deposits	-
1040-Other Special Deposits	-
1060-Term Deposits	-
1070-Current Investments	-
1100-Customer Accounts Receivable	3,335,356.00
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	(91,124.00)
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	212,376.00
1120-Accrued Utility Revenues	4,684,292.00
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(333,817.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1170-Notes Receivable	-
1180-Prepayments	284,201.00
1190-Miscellaneous Current and Accrued Assets	-
1200-Accounts Receivable from Associated Companies	(492,367.00)
1210-Notes Receivable from Associated Companies	-
Current Assets Total	**13,361,317.34**

Inventory	
1305-Fuel Stock	-
1330-Plant Materials and Operating Supplies	918,765.00
1340-Merchandise	-
1350-Other Material and Supplies	-
Inventory Total	**918,765.00**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1408-Long Term Receivable - Street Lighting Transfer	-
1410-Other Special or Collateral Funds	-
1415-Sinking Funds	-
1425-Unamortized Debt Expense	-
1445-Unamortized Discount on Long-Term Debt--Debit	-
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	-
1460-Other Non-Current Assets	-
1465-O.M.E.R.S. Past Service Costs	-
1470-Past Service Costs - Employee Future Benefits	-
1475-Past Service Costs -Other Pension Plans	-
1480-Portfolio Investments - Associated Companies	-
1485-Investment In Subsidiary Companies - Significant Influence	-
1490-Investment in Subsidiary Companies	-
1150-Non-Current Assets Total	**-**

Other Assets and Deferred Charges

1505-Unrecovered Plant and Regulatory Study Costs	-
1508-Other Regulatory Assets	205,459.00
1510-Preliminary Survey and Investigation Charges	-
1515-Emission Allowance Inventory	-
1516-Emission Allowance Withheld	-
1518-RCVA - Retail	423,740.00
1525-Miscellaneous Deferred Debits	3,235.00
1530-Deferred Losses from Disposition of Utility Plant	-
1540-Deferred Losses from Disposition of Utility Plant	-
1545-Development Charge Deposits/ Receivables	-
1548-RCVA - Service Transaction Request (STR)	5,955.00
1550-LV Charges - Variance	(438,071.00)
1555-Smart Meters Recovery	3,434,511.00
1556-Smart Meters OM & A	453,618.00
1562-Deferred PILs	994,579.00
1563-Deferred PILs - Contra	-
1565-C & DM Costs	16,284.38
1566-C & DM Costs Contra	(16,284.40)
1570-Qualifying Transition Costs	(529,646.00)
1571-Pre Market CofP Variance	-
1572-Extraordinary Event Losses	-
1574-Deferred Rate Impact Amounts	-
1580-RSVA - Wholesale Market Services	(1,049,907.00)
1582-RSVA - One-Time	-
1584-RSVA - Network Charges	120,557.00
1586-RSVA - Connection Charges	254,728.00
1588-RSVA - Commodity (Power)	189,886.00
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	392,096.00
Other Assets and Deferred Charges Total	**4,460,739.98**

Distribution Plant	
1805-Land	-
1806-Land Rights	-
1808-Buildings and Fixtures	-
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	580,902.71
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	16,778,063.45
1835-Overhead Conductors and Devices	9,068,545.46
1840-Underground Conduit	608,270.43
1845-Underground Conductors and Devices	6,704,485.17
1850-Line Transformers	10,442,316.01
1855-Services	2,333,704.56
1860-Meters	2,773,947.33
1865-Other Installations on Customer's Premises	-
Distribution Plant Total	**49,290,235.12**

General Plant	
1905-Land	139,071.47
1906-Land Rights	695,389.04
1908-Buildings and Fixtures	2,013,342.26
1910-Leasehold Improvements	-
1915-Office Furniture and Equipment	346,247.85
1920-Computer Equipment - Hardware	545,645.53
1925-Computer Software	2,192,909.47
1930-Transportation Equipment	1,772,082.85
1935-Stores Equipment	-
1940-Tools, Shop and Garage Equipment	515,534.77
1945-Measurement and Testing Equipment	-
1950-Power Operated Equipment	-
1955-Communication Equipment	66,281.42
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1975-Load Management Controls - Utility Premises	-
1980-System Supervisory Equipment	-
1985-Sentinel Lighting Rentals	-
1990-Other Tangible Property	-
1995-Contributions and Grants	(2,724,218.94)
General Plant Total	**5,562,285.72**

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

Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(20,208,347.17)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(194,727.49)
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	-
2160-Accumulated Amortization of Other Utility Plant	-
2180-Accumulated Amortization of Non-Utility Property	-
Accumulated Amortization Total	**(20,403,074.66)**

Total Assets	**53,190,268.50**

Current Liabilities	
2205-Accounts Payable	1,746,027.00
2208-Customer Credit Balances	-
2210-Current Portion of Customer Deposits	230,000.00
2215-Dividends Declared	-
2220-Miscellaneous Current and Accrued Liabilities	3,514,633.00
2225-Notes and Loans Payable	-
2240-Accounts Payable to Associated Companies	-
2242-Notes Payable to Associated Companies	-
2250-Competition Transition Charges Payable	240,231.00
2252-Transmission Charges Payable	-
2254-Electric Safety Authority Fees Payable	-
2256-Independent Market Operator Fees and Penalties Payable	-
2260-Current Portion of Long Term Debt	6,240,187.00
2262-Ontario Hydro Debt - Current Portion	-
2264-Pensions and Employee Benefits - Current Portion	-
2268-Accrued Interest on Long Term Debt	-
2270-Matured Long Term Debt	-
2272-Matured Interest on Long Term Debt	-
2285-Obligations Under Capital Leases--Current	-
2290-Commodity Taxes	18,998.00
2292-Payroll Deductions / Expenses Payable	170,302.00
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	(542,111.00)
2296-Future Income Taxes - Current	422,481.00
Current Liabilities Total	**12,040,748.00**

Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	-
2306-Employee Future Benefits	-
2308-Other Pensions - Past Service Liability	-
2310-Vested Sick Leave Liability	-
2315-Accumulated Provision for Rate Refunds	-
2320-Other Miscellaneous Non-Current Liabilities	-
2325-Obligations Under Capital Lease--Non-Current	-
2330-Devolpment Charge Fund	-
2335-Long Term Customer Deposits	206,567.00
2340-Collateral Funds Liability	-
2345-Unamortized Premium on Long Term Debt	-
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	-
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2410-Deferred Gains From Disposition of Utility Plant	-
2415-Unamortized Gain on Reacquired Debt	-
2425-Other Deferred Credits	-
2435-Accrued Rate-Payer Benefit	-
Non-Current Liabilities Total	**206,567.00**

Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	11,753,544.00
2510-Debenture Advances	-
2515-Required Bonds	-
2520-Other Long Term Debt	-

2525-Term Bank Loans - Long Term Portion	400,000.00
2530-Ontario Hydro Debt Outstanding - Long Term Portion	-
2550-Advances from Associated Companies	-
Long-Term Debt Total	**12,153,544.00**

Shareholders' Equity	
3005-Common Shares Issued	17,144,796.00
3008-Preference Shares Issued	-
3010-Contributed Surplus	-
3020-Donations Received	-
3022-Devolpment Charges Transferred to Equity	-
3026-Capital Stock Held in Treasury	-
3030-Miscellaneous Paid-In Capital	2,735,909.00
3035-Installments Received on Capital Stock	-
3040-Appropriated Retained Earnings	-
3045-Unappropriated Retained Earnings	8,473,802.05
3046-Balance Transferred From Income	950,710.45
3047-Appropriations of Retained Earnings - Current Period	-
3048-Dividends Payable-Preference Shares	-
3049-Dividends Payable-Common Shares	(515,808.00)
3055-Adjustment to Retained Earnings	-
3065-Unappropriated Undistributed Subsidiary Earnings	-
Shareholders' Equity Total	**28,789,409.50**

Total Liabilities & Shareholder's Equity	**53,190,268.50**

Balance Sheet Total	0.00

HALDIMAND COUNTY HYDRO INC.
2009 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
Sales of Electricity	
4006-Residential Energy Sales	(10,816,578.00)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(149,025.00)
4030-Sentinel Energy Sales	(28,634.00)
4035-General Energy Sales	(11,189,436.00)
4040-Other Energy Sales to Public Authorities	-
4045-Energy Sales to Railroads and Railways	-
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	-
4062-Billed WMS	(2,326,495.00)
4064-Billed WMS-One Time	-
4066-Billed NW	(1,790,955.00)
4068-Billed CN	(1,682,412.00)
4075-Billed LV	(301,683.00)
Sales of Electricity Total	**(28,285,218.00)**
Revenues From Services - Distribution	
4080-Distribution Services Revenue	(11,203,647.00)
4082-Retail Services Revenue	(32,268.00)
4084-Service Transaction Req STR Revenue	(1,020.00)
4090-Electric Services Incidental to Energy Sales	(107,425.00)
Revenues From Services - Distribution Total	**(11,344,360.00)**
Other Operating Revenues	
4205-Interdepartmental Rents	-
4210-Rent from Electric Property	(107,197.00)
4215-Other Utility Operating Income	-
4220-Other Electric Revenues	-
4225-Late Payment Charges	(319,125.00)
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues	(133,200.00)
4240-Provision for Rate Refunds	-
4245-Government Assistance Directly Credited to Income	-
Other Operating Revenues Total	**(559,522.00)**
Other Income & Deductions	
4305-Regulatory Debits	-
4310-Regulatory Credits	-
4315-Revenues from Electric Plant Leased to Others	-
4320-Expenses of Electric Plant Leased to Others	-
4325-Revenues from Merchandise, Jobbing, Etc.	(10,100.00)
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	-
4360-Loss on Disposition of Utility and Other Property	-
4365-Gains from Disposition of Allowances for Emission	-
4370-Losses from Disposition of Allowances for Emission	-
4375-Revenues from Non-Utility Operations	(359,822.85)
4375-1-Revenues from Non-Utility Operations (CDM Programs)	(35,000.00)
4380-Expenses of Non-Utility Operations	-
4385-Expenses of Non-Utility Operations	-
4390-Miscellaneous Non-Operating Income	(63,140.00)
4395-Rate-Payer Benefit Including Interest	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
Other Income & Deductions Total	**(468,062.85)**
Investment Income	
4405-Interest and Dividend Income	(67,548.00)
4405-1-OEB Deferred Interest	(20,390.00)
4415-Equity in Earnings of Subsidiary Companies	-
Investment Income Total	**(87,938.00)**
Power Supply Expenses	
4705-Power Purchased	22,183,673.00
4708-Charges WMS	2,326,495.00
4710-Cost of Power Adjustments	-
4712-Charges - One Time	-
4714-Charges NW	1,790,955.00
4715-System Control and Load Dispatching	-
4716-Charges CN	1,682,412.00
4720-Other Expenses	-
4725-Competition Transition Expense	-
4730-Rural Rate Assistance Expense	-
4750-Charges LV	301,683.00
Power Supply Expenses Total	**28,285,218.00**
Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	492,414.00
5010-Load Dispatching	-
5012-Station Buildings and Fixtures Expense	-
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	17,334.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	19,000.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	115,403.00
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers - Operation	212,380.00
5040-Underground Distribution Lines and Feeders - Operation Labour	57,554.00
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	-
5050-Underground Subtransmission Feeders - Operation	-
5055-Underground Distribution Transformers - Operation	15,186.00
5060-Street Lighting and Signal System Expense	-
5065-Meter Expense	257,227.00

5070-Customer Premises - Operation Labour	13,127.00
5075-Customer Premises - Materials and Expenses	-
5085-Miscellaneous Distribution Expense	186,655.00
5090-Underground Distribution Lines and Feeders - Rental Paid	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	-
Distribution Expenses - Operation Total	**1,386,280.00**

Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	125,994.00
5110-Maintenance of Structures	-
5112-Maintenance of Transformer Station Equipment	-
5114-Mtaint Dist Stn Equip	90,167.00
5120-Maintenance of Poles, Towers and Fixtures	637,848.00
5125-Maintenance of Overhead Conductors and Devices	848,105.00
5130-Maintenance of Overhead Services	151,442.00
5135-Overhead Distribution Lines and Feeders - Right of Way	564,461.00
5145-Maintenance of Underground Conduit	9,574.00
5150-Maintenance of Underground Conductors and Devices	37,325.00
5155-Maintenance of Underground Services	108,412.00
5160-Maintenance of Line Transformers	166,502.00
5165-Maintenance of Street Lighting and Signal Systems	-
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Materials and Expenses	-
5175-Maintenance of Meters	25,366.00
5178-Customer Installations Expenses - Leased Property	-
5195-Maintenance of Other Installations on Customer Premises	2,048.00
Distribution Expenses - Maintenance Total	**2,767,244.00**

Billing and Collecting	
5305-Supervision	142,969.00
5310-Meter Reading Expense	280,668.00
5315-Customer Billing	580,156.00
5320-Collecting	250,781.00
5325-Collecting - Cash Over and Short	-
5330-Collection Charges	-
5335-Bad Debt Expense	30,000.00
5340-Miscellaneous Customer Accounts Expenses	70,761.00
Billing and Collecting Total	**1,355,335.00**

Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	27,972.00
5415-Energy Conservation	18,000.00
5420-Community Safety Program	-
5425-Miscellaneous Customer Service and Informational Expenses	-
Community Relations Total	**45,972.00**

Administrative and General Expenses	
5605-Executive Salaries and Expenses	71,428.00
5610-Management Salaries and Expenses	638,854.00
5615-General Administrative Salaries and Expenses	524,809.00
5620-Office Supplies and Expenses	106,564.00
5625-Administrative Expense Transferred-Credit	-
5630-Outside Services Employed	385,077.40
5635-Property Insurance	18,844.00
5640-Injuries and Damages	-
5645-Employee Pensions and Benefits	-
5650-Franchise Requirements	-
5655-Regulatory Expenses	87,070.00
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	57,355.00
5670-Rent	-
5675-Maintenance of General Plant	-
5680-Electrical Safety Authority Fees	-
5685-Independent Market Operator Fees and Penalties	-
5695-OM&A Contra Account	-
Administrative and General Expenses Total	**1,890,001.40**

Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	2,796,201.00
5710-Amortization of Limited Term Electric Plant	-
5715-Amortization of Intangibles and Other Electric Plant	17,775.00
5720-Amortization of Electric Plant Acquisition Adjustments	-
5725-Miscellaneous Amortization	-
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	-
5735-Amortization of Deferred Development Costs	-
5740-Amortization of Deferred Charges	-
Amortization Expense Total	**2,813,976.00**

Interest Expense	
6005-Interest on Long Term Debt	676,146.00
6010-Amortization of Debt Discount and Expense	-
6015-Amortization of Premium on Debt-Credit	-
6020-Amortization of Loss on Reacquired Debt	-
6025-Amortization of Gain on Reacquired Debt-Credit	-
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	-
6040-Allowance for Borrowed Funds Used During Construction-Credit	-
6042-Allowance for Other Funds Used During Construction	-
6045-Interest Expense on Capital Lease Obligations	-
Interest Expense Total	**676,146.00**

Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes - Property Tax	51,937.00
6105-Taxes Other Than Income Taxes - Capital Tax	54,021.00
Taxes Other Than Income Taxes Total	**105,958.00**

Income Taxes	
6110-Income Taxes	(674,686.00)
6115-Provision for Future Income Taxes	1,142,946.00
Income Taxes Total	**468,260.00**
4100-Extraordinary & Other Items	
6205-Donations	-
6210-Life Insurance	-
6215-Penalties	-
6225-Other Deductions	-
4100-Extraordinary & Other Items Total	**-**
Net Income - (Gain)/Loss	**(950,710.45)**

HALDIMAND COUNTY HYDRO INC.
2010 BALANCE SHEET

Account Description	Total
Current Assets	
1005-Cash	5,434,673.99
1010-Cash Advances and Working Funds	-
1020-Interest Special Deposits	-
1030-Dividend Special Deposits	-
1040-Other Special Deposits	-
1060-Term Deposits	-
1070-Current Investments	-
1100-Customer Accounts Receivable	3,475,613.00
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	(91,124.00)
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	212,376.00
1120-Accrued Utility Revenues	4,920,747.00
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(347,561.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1170-Notes Receivable	-
1180-Prepayments	284,201.00
1190-Miscellaneous Current and Accrued Assets	-
1200-Accounts Receivable from Associated Companies	(667,170.00)
1210-Notes Receivable from Associated Companies	-
Current Assets Total	**13,221,755.99**

Inventory	
1305-Fuel Stock	-
1330-Plant Materials and Operating Supplies	918,765.00
1340-Merchandise	-
1350-Other Material and Supplies	-
Inventory Total	**918,765.00**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1408-Long Term Receivable - Street Lighting Transfer	-
1410-Other Special or Collateral Funds	-
1415-Sinking Funds	-
1425-Unamortized Debt Expense	-
1445-Unamortized Discount on Long-Term Debt--Debit	-
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	-
1460-Other Non-Current Assets	-
1465-O.M.E.R.S. Past Service Costs	-
1470-Past Service Costs - Employee Future Benefits	-
1475-Past Service Costs -Other Pension Plans	-
1480-Portfolio Investments - Associated Companies	-
1485-Investment In Subsidiary Companies - Significant Influence	-
1490-Investment in Subsidiary Companies	-
1150-Non-Current Assets Total	**-**

Other Assets and Deferred Charges

1505-Unrecovered Plant and Regulatory Study Costs	-
1508-Other Regulatory Assets	-
1510-Preliminary Survey and Investigation Charges	-
1515-Emission Allowance Inventory	-
1516-Emission Allowance Withheld	-
1518-RCVA - Retail	144,911.00
1525-Miscellaneous Deferred Debits	-
1530-Deferred Losses from Disposition of Utility Plant	-
1540-Deferred Losses from Disposition of Utility Plant	-
1545-Development Charge Deposits/ Receivables	-
1548-RCVA - Service Transaction Request (STR)	2,241.00
1550-LV Charges - Variance	(182,199.00)
1555-Smart Meters Recovery	3,209,915.00
1556-Smart Meters OM & A	946,458.00
1562-Deferred PILs	998,779.00
1563-Deferred PILs - Contra	-
1565-C & DM Costs	16,284.38
1566-C & DM Costs Contra	(16,284.40)
1570-Qualifying Transition Costs	-
1571-Pre Market CofP Variance	-
1572-Extraordinary Event Losses	-
1574-Deferred Rate Impact Amounts	-
1580-RSVA - Wholesale Market Services	(258,206.00)
1582-RSVA - One-Time	-
1584-RSVA - Network Charges	180,128.00
1586-RSVA - Connection Charges	105,851.00
1588-RSVA - Commodity (Power)	(803,422.00)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	-
1595-Disposition and Recovery of Regulatory Asset Balances	(73,553.00)
Other Assets and Deferred Charges Total	**4,270,902.98**

Distribution Plant	
1805-Land	-
1806-Land Rights	-
1808-Buildings and Fixtures	-
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	580,902.71
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	17,504,451.10
1835-Overhead Conductors and Devices	9,641,483.70
1840-Underground Conduit	973,197.37
1845-Underground Conductors and Devices	6,918,988.61
1850-Line Transformers	10,957,680.74
1855-Services	2,529,708.56
1860-Meters	2,861,710.33
1865-Other Installations on Customer's Premises	-
Distribution Plant Total	**51,968,123.12**

General Plant	
1905-Land	139,071.47
1906-Land Rights	695,389.04
1908-Buildings and Fixtures	2,013,342.26
1910-Leasehold Improvements	-
1915-Office Furniture and Equipment	351,583.85
1920-Computer Equipment - Hardware	564,321.53
1925-Computer Software	2,621,977.47
1930-Transportation Equipment	2,045,682.85
1935-Stores Equipment	-
1940-Tools, Shop and Garage Equipment	554,867.77
1945-Measurement and Testing Equipment	-
1950-Power Operated Equipment	-
1955-Communication Equipment	66,281.42
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1975-Load Management Controls - Utility Premises	-
1980-System Supervisory Equipment	-
1985-Sentinel Lighting Rentals	-
1990-Other Tangible Property	-
1995-Contributions and Grants	(2,855,818.94)
General Plant Total	**6,196,698.72**

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

Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(23,122,659.03)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(212,502.16)
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	-
2160-Accumulated Amortization of Other Utility Plant	-
2180-Accumulated Amortization of Non-Utility Property	-
Accumulated Amortization Total	**(23,335,161.19)**

Total Assets	**53,241,084.62**

Current Liabilities	
2205-Accounts Payable	1,798,407.00
2208-Customer Credit Balances	-
2210-Current Portion of Customer Deposits	230,000.00
2215-Dividends Declared	-
2220-Miscellaneous Current and Accrued Liabilities	3,541,868.00
2225-Notes and Loans Payable	-
2240-Accounts Payable to Associated Companies	-
2242-Notes Payable to Associated Companies	-
2250-Competition Transition Charges Payable	239,510.00
2252-Transmission Charges Payable	-
2254-Electric Safety Authority Fees Payable	-
2256-Independent Market Operator Fees and Penalties Payable	-
2260-Current Portion of Long Term Debt	1,047,413.00
2262-Ontario Hydro Debt - Current Portion	-
2264-Pensions and Employee Benefits - Current Portion	-
2268-Accrued Interest on Long Term Debt	-
2270-Matured Long Term Debt	-
2272-Matured Interest on Long Term Debt	-
2285-Obligations Under Capital Leases--Current	-
2290-Commodity Taxes	19,568.00
2292-Payroll Deductions / Expenses Payable	175,411.00
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	423,548.00
2296-Future Income Taxes - Current	305,469.00
Current Liabilities Total	**7,781,194.00**

Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	-
2306-Employee Future Benefits	-
2308-Other Pensions - Past Service Liability	-
2310-Vested Sick Leave Liability	-
2315-Accumulated Provision for Rate Refunds	-
2320-Other Miscellaneous Non-Current Liabilities	-
2325-Obligations Under Capital Lease--Non-Current	-
2330-Devolpment Charge Fund	-
2335-Long Term Customer Deposits	206,567.00
2340-Collateral Funds Liability	-
2345-Unamortized Premium on Long Term Debt	-
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	-
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2410-Deferred Gains From Disposition of Utility Plant	-
2415-Unamortized Gain on Reacquired Debt	-
2425-Other Deferred Credits	-
2435-Accrued Rate-Payer Benefit	-
Non-Current Liabilities Total	**206,567.00**

Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	14,907,751.00
2510-Debenture Advances	-
2515-Required Bonds	-
2520-Other Long Term Debt	-

2525-Term Bank Loans - Long Term Portion	200,000.00
2530-Ontario Hydro Debt Outstanding - Long Term Portion	-
2550-Advances from Associated Companies	-
Long-Term Debt Total	**15,107,751.00**

Shareholders' Equity	
3005-Common Shares Issued	17,144,796.00
3008-Preference Shares Issued	-
3010-Contributed Surplus	-
3020-Donations Received	-
3022-Devolpment Charges Transferred to Equity	-
3026-Capital Stock Held in Treasury	-
3030-Miscellaneous Paid-In Capital	2,735,909.00
3035-Installments Received on Capital Stock	-
3040-Appropriated Retained Earnings	-
3045-Unappropriated Retained Earnings	8,908,704.50
3046-Balance Transferred From Income	1,593,840.12
3047-Appropriations of Retained Earnings - Current Period	-
3048-Dividends Payable-Preference Shares	-
3049-Dividends Payable-Common Shares	(237,677.00)
3055-Adjustment to Retained Earnings	-
3065-Unappropriated Undistributed Subsidiary Earnings	-
Shareholders' Equity Total	**30,145,572.62**

Total Liabilities & Shareholder's Equity	**53,241,084.62**

Balance Sheet Total	0.00

HALDIMAND COUNTY HYDRO INC.
2010 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
Sales of Electricity	
4006-Residential Energy Sales	(10,988,302.00)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(150,460.00)
4030-Sentinel Energy Sales	(27,165.00)
4035-General Energy Sales	(11,197,854.00)
4040-Other Energy Sales to Public Authorities	-
4045-Energy Sales to Railroads and Railways	-
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	-
4062-Billed WMS	(2,373,264.00)
4064-Billed WMS-One Time	-
4066-Billed NW	(1,955,675.00)
4068-Billed CN	(1,775,798.00)
4075-Billed LV	(209,412.00)
Sales of Electricity Total	**(28,677,930.00)**
Revenues From Services - Distribution	
4080-Distribution Services Revenue	(12,823,643.00)
4082-Retail Services Revenue	(34,956.00)
4084-Service Transaction Req STR Revenue	(1,070.00)
4090-Electric Services Incidental to Energy Sales	(107,127.00)
Revenues From Services - Distribution Total	**(12,966,796.00)**
Other Operating Revenues	
4205-Interdepartmental Rents	-
4210-Rent from Electric Property	(79,358.00)
4215-Other Utility Operating Income	-
4220-Other Electric Revenues	-
4225-Late Payment Charges	(319,125.00)
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues	(133,200.00)
4240-Provision for Rate Refunds	-
4245-Government Assistance Directly Credited to Income	-
Other Operating Revenues Total	**(531,683.00)**
Other Income & Deductions	
4305-Regulatory Debits	-
4310-Regulatory Credits	-
4315-Revenues from Electric Plant Leased to Others	-
4320-Expenses of Electric Plant Leased to Others	-
4325-Revenues from Merchandise, Jobbing, Etc.	(10,400.00)
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	-
4360-Loss on Disposition of Utility and Other Property	-
4365-Gains from Disposition of Allowances for Emission	-
4370-Losses from Disposition of Allowances for Emission	-
4375-Revenues from Non-Utility Operations	(359,822.85)
4375-1-Revenues from Non-Utility Operations (CDM Programs)	(35,000.00)
4380-Expenses of Non-Utility Operations	-
4385-Expenses of Non-Utility Operations	-
4390-Miscellaneous Non-Operating Income	(2,727.00)
4395-Rate-Payer Benefit Including Interest	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
Other Income & Deductions Total	**(407,949.85)**
Investment Income	
4405-Interest and Dividend Income	(67,548.00)
4405-1-OEB Deferred Interest	(24,646.00)
4415-Equity in Earnings of Subsidiary Companies	-
Investment Income Total	**(92,194.00)**
Power Supply Expenses	
4705-Power Purchased	22,363,781.00
4708-Charges WMS	2,373,264.00
4710-Cost of Power Adjustments	-
4712-Charges - One Time	-
4714-Charges NW	1,955,675.00
4715-System Control and Load Dispatching	-
4716-Charges CN	1,775,798.00
4720-Other Expenses	-
4725-Competition Transition Expense	-
4730-Rural Rate Assistance Expense	-
4750-Charges LV	209,412.00
Power Supply Expenses Total	**28,677,930.00**
Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	499,249.00
5010-Load Dispatching	-
5012-Station Buildings and Fixtures Expense	-
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	17,889.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	19,570.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	120,005.00
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers - Operation	221,961.00
5040-Underground Distribution Lines and Feeders - Operation Labour	58,608.00
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	-
5050-Underground Subtransmission Feeders - Operation	-
5055-Underground Distribution Transformers - Operation	15,696.00
5060-Street Lighting and Signal System Expense	-
5065-Meter Expense	276,493.00

5070-Customer Premises - Operation Labour	15,294.00
5075-Customer Premises - Materials and Expenses	-
5085-Miscellaneous Distribution Expense	192,883.00
5090-Underground Distribution Lines and Feeders - Rental Paid	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	-
Distribution Expenses - Operation Total	**1,437,648.00**

Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	129,706.00
5110-Maintenance of Structures	-
5112-Maintenance of Transformer Station Equipment	-
5114-Mtaint Dist Stn Equip	107,029.00
5120-Maintenance of Poles, Towers and Fixtures	607,398.00
5125-Maintenance of Overhead Conductors and Devices	900,963.00
5130-Maintenance of Overhead Services	158,103.00
5135-Overhead Distribution Lines and Feeders - Right of Way	556,518.00
5145-Maintenance of Underground Conduit	10,687.00
5150-Maintenance of Underground Conductors and Devices	33,209.00
5155-Maintenance of Underground Services	111,495.00
5160-Maintenance of Line Transformers	159,370.00
5165-Maintenance of Street Lighting and Signal Systems	-
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Materials and Expenses	-
5175-Maintenance of Meters	26,272.00
5178-Customer Installations Expenses - Leased Property	-
5195-Maintenance of Other Installations on Customer Premises	1,983.00
Distribution Expenses - Maintenance Total	**2,802,733.00**

Billing and Collecting	
5305-Supervision	144,980.00
5310-Meter Reading Expense	296,609.32
5315-Customer Billing	602,980.00
5320-Collecting	254,886.00
5325-Collecting - Cash Over and Short	-
5330-Collection Charges	-
5335-Bad Debt Expense	30,000.00
5340-Miscellaneous Customer Accounts Expenses	73,968.00
Billing and Collecting Total	**1,403,423.32**

Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	28,836.00
5415-Energy Conservation	18,000.00
5420-Community Safety Program	-
5425-Miscellaneous Customer Service and Informational Expenses	-
Community Relations Total	**46,836.00**

Administrative and General Expenses	
5605-Executive Salaries and Expenses	71,428.00
5610-Management Salaries and Expenses	654,364.08
5615-General Administrative Salaries and Expenses	542,980.60
5620-Office Supplies and Expenses	112,380.00
5625-Administrative Expense Transferred-Credit	-
5630-Outside Services Employed	402,106.20
5635-Property Insurance	19,408.00
5640-Injuries and Damages	-
5645-Employee Pensions and Benefits	-
5650-Franchise Requirements	-
5655-Regulatory Expenses	101,208.00
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	57,455.00
5670-Rent	-
5675-Maintenance of General Plant	-
5680-Electrical Safety Authority Fees	-
5685-Independent Market Operator Fees and Penalties	-
5695-OM&A Contra Account	-
Administrative and General Expenses Total	**1,961,329.88**

Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	2,914,311.86
5710-Amortization of Limited Term Electric Plant	-
5715-Amortization of Intangibles and Other Electric Plant	17,774.67
5720-Amortization of Electric Plant Acquisition Adjustments	-
5725-Miscellaneous Amortization	-
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	-
5735-Amortization of Deferred Development Costs	-
5740-Amortization of Deferred Charges	-
Amortization Expense Total	**2,932,086.53**

Interest Expense	
6005-Interest on Long Term Debt	1,032,383.00
6010-Amortization of Debt Discount and Expense	-
6015-Amortization of Premium on Debt-Credit	-
6020-Amortization of Loss on Reacquired Debt	-
6025-Amortization of Gain on Reacquired Debt-Credit	-
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	-
6040-Allowance for Borrowed Funds Used During Construction-Credit	-
6042-Allowance for Other Funds Used During Construction	-
6045-Interest Expense on Capital Lease Obligations	-
Interest Expense Total	**1,032,383.00**

Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes - Property Tax	53,447.00
6105-Taxes Other Than Income Taxes - Capital Tax	18,823.00
Taxes Other Than Income Taxes Total	**72,270.00**

Income Taxes	
6110-Income Taxes	833,085.00
6115-Provision for Future Income Taxes	(117,012.00)
Income Taxes Total	**716,073.00**
4100-Extraordinary & Other Items	
6205-Donations	-
6210-Life Insurance	-
6215-Penalties	-
6225-Other Deductions	-
4100-Extraordinary & Other Items Total	**-**
Net Income - (Gain)/Loss	**(1,593,840.12)**

HALDIMAND COUNTY UTILITIES INC.

ANNUAL REPORT 2008

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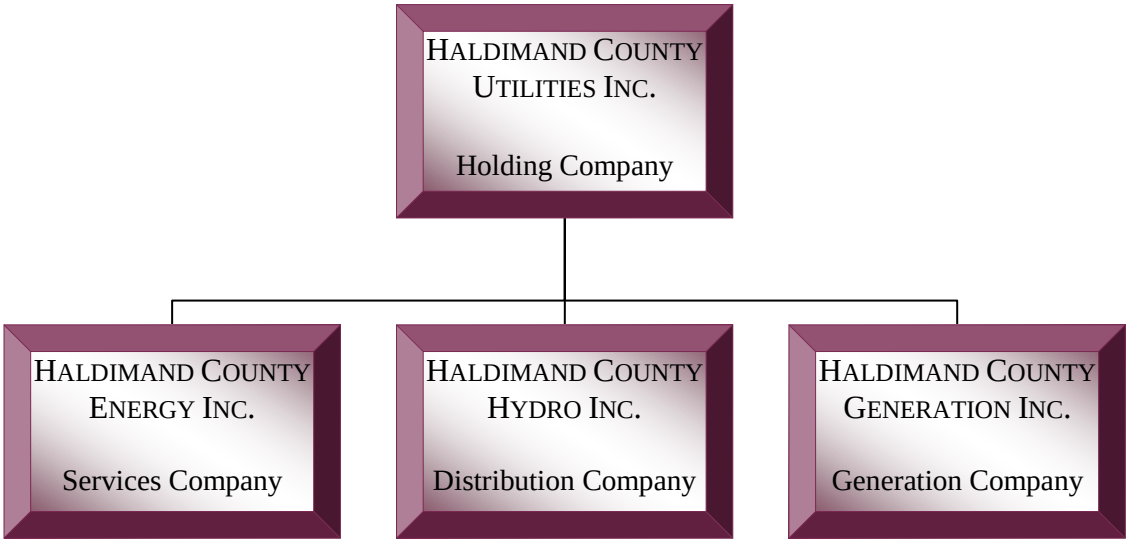
HCUI Corporate Structure



Haldimand County Utilities Inc. is the Holding Company for the Distribution, Services, and Generation Companies.

The Corporation was formed in October 2000 following provincial government legislation, by amalgamating the former Hydro Electric Commissions of Dunnville, Haldimand and east portion of Nanticoke.

Haldimand County holds 100% of the shares of the Holding Company, which in turn holds 100% of the shares of each of the Distribution, Services and Generation Companies.

2008 BOARD OF DIRECTORS

Haldimand County Utilities Inc.

Robert M. Hunsinger, Chair	November 1, 2000 – Present
Councillor Buck Sloat, Vice-Chair	April 1, 2005 – Present
Mayor Marie Trainer	December 1, 2003 – Present
Peter D. Smuk	July 1, 2007 – Present

Haldimand County Hydro Inc.

Robert M. Hunsinger, Chair	November 1, 2000 – Present
Councillor Buck Sloat, Vice-Chair	April 1, 2005 – Present
Mayor Marie Trainer	December 1, 2003 – Present
Peter D. Smuk	August 24, 2005 – Present
Craig R. Sitter	January 1, 2006 – March 13, 2009
Brian Snyder	January 1, 2007 – Present
Albert Marshall	January 1, 2007 - Present
Alec Cowan	July 1, 2007 – Present

Haldimand County Energy Inc.

Robert M. Hunsinger, Chair	January 1, 2004 – Present
Councillor Buck Sloat, Vice-Chair	April 1, 2005 – Present
Mayor Marie Trainer	April 1, 2005 – Present
Peter D. Smuk	July 1, 2007 – Present

Haldimand County Generation Inc.

Robert M. Hunsinger, Chair	January 1, 2004 – Present
Councillor Buck Sloat, Vice-Chair	January 1, 2007 – Present

MANAGEMENT TEAM

President & CEO	Lloyd E. Payne, P. Eng., M.B.A.
Consumer Services Manager	R. Jane Albert
Engineering Manager	Ed Galinski, P. Eng.
Finance Manager	Jacqueline A. Scott
Operations Manager	Doug Curtiss, P. Eng.

MESSAGE FROM THE CHAIR

On behalf of the Board of Directors I am pleased to report on the activities of Haldimand County Utilities Inc. and its subsidiary companies for 2008.

When I was appointed to the position of Chair in 2005 the electricity distribution industry was still struggling with the impacts of restructuring. Today, much has been resolved but many challenges remain and new challenges are imminent including those resulting from the new "*Green Energy and Green Economy Act, 2009*" which was passed by the Ontario Legislature on May 14, 2009. This Act could potentially require significant capital upgrades to the distribution grid as it encourages and facilitates distributed generation and proposes "smart grids" across the Province.

Net income for 2008 amounted to $2,063,232 compared to $1,798,508 for the previous year. Dividends in the amount of $449,627 were paid to our shareholder during 2008 bringing the total dividend payments since incorporation in 2000 to $1,850,309. Based upon 2008 net income a dividend in the amount of $515,808 has been declared by the Board for payment in 2009.

Haldimand County Hydro was very active once again in delivering energy conservation programs and incentives to our customers. These programs were developed and financed by the Ontario Power Authority. During 2008 the Haldimand County Hydro promotional tent was present at each community's local festivals, and took a County-wide focused approach to promoting these programs through bill messages and inserts, newspaper advertisements, as well as a breakfast meeting for industrial and institutional customers. Although customer participation varied from program to program, it is evident that Haldimand County residents and businesses are embracing energy conservation. Energy Conservation week was launched at River Heights Elementary School in Caledonia with over 100 grade 5 students in attendance to play "*Are you as Energy Smart as a Haldimand County 5th Grader*". Encouraging good energy use habits to youth will be key to a sustainable future.

I would also like to comment on two initiatives which will feature prominently in 2009. Smart meters are receiving much attention worldwide and the Provincial government has legislated their installation throughout Ontario by 2010. Haldimand County Hydro will commence installing smart meters throughout Haldimand County during 2009. However, these smart meters will be used initially as regular meters and billing on time of use will commence at a time in the future as determined in conjunction with the Ontario Energy Board. We understand the importance of communicating to our customers about this new technology and how it will affect them and consequently are developing a customer communication portfolio which will be rolled out in coordination with the deployment and commencement of time of use billing.

A major initiative by the Ontario Energy Board involves subjecting each of the approximately 80 electricity distribution utilities in the province to detailed "Cost of Service" review over a 3 year period with approximately one third of the utilities being reviewed each year. Haldimand County Hydro has been assigned to the last group and will be expected to submit its lengthy application by August, 2009 for rates effective May 1, 2010.

Haldimand County Energy Inc. continued its operation of the sentinel light rental program during 2008. Rental rates were increased by 3% effective January 1, 2008 for the first time in 4 years. This corporation also provides water and sewer billing services to Haldimand County.

As I will leave the Board in October, 2009 I reflect on the enormous changes which have taken place in the industry, and in Haldimand County specifically, since I first joined Haldimand Hydro-Electric Commission as commissioner in December, 1993. The many challenges have been met and overcome and I believe Haldimand County Hydro is well positioned as a utility of which all of us – Shareholder, residents, staff, and Directors – can be justifiably proud. I am confident that the future of Haldimand County Utilities Inc. is in capable hands. It has been an honour and a pleasure to serve on this Board and I thank you for that opportunity.

Bob Hunsinger
Chair

MESSAGE FROM THE PRESIDENT &CEO

Haldimand County Hydro continued its emphasis on improving customer service and reliability during 2008. This emphasis is evidenced by the $4.6 million capital program in 2008, up from $2.9 million in each of 2006 and 2007. We understand that electricity is an essential service and are confident that our capital works and maintenance programs are making a difference towards meeting the service and reliability expectations of our customers.

Work progressed steadily during the year on the installation of a new customer information and billing system following award of the contract on April 3, 2008. This major undertaking commenced live operation on March 1, 2009.

Work continued on the multi-year project started in 2007 to construct a new line between Jarvis Transformer Station and Hagersville. During 2008 work continued on line sections between the communities of Hagersville and Jarvis. This project and the purchase of line sections from Hydro One will improve the capacity and reliability of supply to Hagersville, Jarvis, and Townsend as well as reduce electrical losses and low voltage charges from Hydro One. On February 28, 2008 the Ontario Energy Board approved the sale of two line sections from Hydro One to Haldimand County Hydro for $145,000 as follows:

- part of the 57M3 feeder involving 7.8 km of 27.6 kV line, and
- the 57M5 feeder out of Jarvis Transformer Station involving 3.7 km of 27.6 kV line.

The ongoing program to test all poles within Haldimand County resulted in replacement of 89 defective poles during the year. This program and the annual tree trimming program are positively impacting reliability of the electricity system for all customers. Tree trimming occurs on a 5 year cycle over which all of Haldimand County is covered and during 2008 the third year of the second cycle occurred with tree trimming in Canborough, Moulton, and Sherbrooke.

Extensive substation work was undertaken at two locations:

- a new 5 MVA transformer was purchased and installed at Decewsville Distribution Station to replace three 1 MVA transformers built in 1949;
- a portable transformer was rented and installed at Canfield Distribution Station to facilitate general testing of the existing 5 MVA transformer and major station rebuilding work.

Environmental remediation of the former Rainham Distribution Station site on Fisherville Road was completed late in 2007 and sale of the land closed on June 5, 2008. Remediation work at the former Forest Distribution Station site in Dunnville was completed in late 2008 with disposal of this property planned for 2009.

Nanticoke Distribution Station on Concession 3 Road (Walpole) was permanently taken out of service on December 4, 2008 upon completion of the capital project to convert its feeders from 8 kV to 27.6 kV. Such projects eliminate the need for future substation maintenance and capital expenditures, improve reliability, and reduce electrical losses. Environmental assessment in preparation for disposal of this substation property is planned for 2010.

Ontario distribution utilities, including Haldimand County Hydro, continued to be impacted by the introduction of the Ontario Power Authority's "*Renewable Energy Standard Offer Program*" launched in November, 2006. Haldimand County Hydro completed 9 "*connection impact assessments*" during 2008 (5 completed during 2007) for potential wind and solar generation projects. Distributed generation on such a scale presents new engineering challenges to ensure the safety and reliability of the distribution system as it was not designed to accommodate such geographically dispersed generation. The first such "*Standard Offer*" project in Haldimand County was the 9.9 MW wind generation project at Mohawk Point which commenced commercial operation on October 24, 2008.

As we look forward to the challenges and opportunities of the future I would like to express my appreciation to our Boards of Directors, and dedicated employees for their enthusiastic efforts to serve our customers and their constant attention to public and employee safety.

Lloyd E. Payne, P. Eng., MBA
President & CEO

MANAGEMENT DISCUSSION AND ANALYSIS

The following discussion and analysis should be read in conjunction with the Consolidated Financial Statements, related Note disclosures and Auditor's Report, as at and for the year ended December 31, 2008. This discussion may contain forward looking statements that are subject to risks, uncertainties and assumptions based on information available as at the date of this report. Management does not intend to update this information and disclaims any legal obligation for actual results that vary from those implied.

HALDIMAND COUNTY UTILITIES INC.

In response to the restructuring and deregulation of Ontario's electricity industry, and pursuant to the *Energy Competition Act (Ontario), 1998* (the "Electricity Act"), Haldimand County Utilities Inc. (the "Corporation") was incorporated under the Ontario Business Corporations Act.

The hydro-electric commissions of the former municipalities of Haldimand and Dunnville and divided City of Nanticoke transferred at book value, their assets and liabilities to the Corporation, effective November 1, 2000. The sole shareholder of the Corporation is the Municipality of Haldimand County (the "County").

The Electricity Act and its enabling regulations distinguish between, and require the separation of, regulated electricity businesses from non-regulated business activities. The Corporation is a holding company, which wholly owns the following subsidiaries:

- Haldimand County Hydro Inc. ("HCHI"), which distributes electricity to residents and businesses within the County.
- Haldimand County Energy Inc. ("HCEI"), which provides non-regulated water and sewer billing, collecting, and customer care services to the County, as well as sentinel light rentals to its customers.
- Haldimand County Generation Inc. ("HCGI"), which is currently an inactive company.

The Corporation's principal business is the regulated distribution of electricity by HCHI. The Consolidated Financial Statements include results for both the regulated and non-regulated business activities of its subsidiaries. The electricity distribution business of the Corporation represented approximately 99% (2007 - 99%) of consolidated assets and 99% (2007 - 99%) of consolidated revenue and other income at year-end.

The Corporation earns revenue from this business by charging its customers for the use of the distribution system. Such electricity distribution charges comprise a fixed monthly service charge combined with a variable (volumetric) charge based on electricity consumption (usage). The distribution rate charged is designed to recover the costs incurred by HCHI in delivering electricity to customers and a rate of return, which is subject to the approval of the provincial regulator, the Ontario Energy Board (the "OEB").

The business distributes electricity through approximately 1,716 kilometres of distribution lines to approximately 20,800 residential and business customers. The distribution system serves most of the residents and businesses within the borders of the County, covering a service territory in the order of 1,252 square kilometres. At the end of 2008 there were 18 (2007 – 26) HCHI customers supplied from the lines of other electricity distributors; conversely, HCHI supplied 129 (2007 – 131) customers outside our service territory for other distributors. Such customer supply arrangements are referred to as "long term load transfers", and the OEB, in accordance with their Distribution System Code, has proposed such arrangements be eliminated before June 30, 2014.

2008 Customers, Consumption and Distribution Revenue by Rate Class

Rate Class	**No. of Customers**	**Consumption (kWh)**		**Distribution Revenue ($)**	
			%		**%**
Residential	18,245	171,781,095	48.8	$ 7,922,649	68.4
General Service < 50 kW	2,351	58,711,522	16.7	$ 1,774,516	15.3
General Service > 50 kW	137	118,305,016	33.6	$ 1,767,919	15.2
Sentinel Lighting *		475,594	0.1	$ 20,509	0.2
Street Lighting *	4	2,328,757	0.7	$ 81,582	0.7
Unmetered Scattered Load *	82	482,264	0.1	$ 19,582	0.2
Total	**20,819**	**352,084,248**	**100.0**	**$ 11,586,757**	**100.0**

(* Sentinel Lights, Street Lights and Unmetered Scattered Loads are billed based on number of "connections", at 647, 2,879 and 84 respectively)

ELECTRICITY DISTRIBUTION REGULATION

In accordance with the *Electricity Act, 1998* and commencing in 1999, the Province of Ontario (the "Province") initiated significant restructuring of the electricity sector, legislating corporatizations of municipal hydro commissions throughout the Province, in addition to a restructuring of the Province's own former hydro business, Ontario Hydro.

On May 1, 2002 the Province opened its wholesale and retail electricity markets to competition by providing generators, retailers and consumers with open access to Ontario's transmission and distribution network ("Market Opening"). This permitted generators, wholesalers, suppliers and marketers to compete to sell electricity to authorized Market Participants. Customers became free to enter into sales contracts with the licensed electricity supplier of their choice. Distributors were required to deliver electricity on behalf of retailers and other suppliers, and were required to supply electricity to Standard Supply Service ("SSS") customers who did not contract with other suppliers for their electricity commodity requirements.

The OEB has regulatory oversight of electricity matters in the Province, which includes the power to issue a distribution licence, mandatory for any entity owning or operating a distribution system. The OEB may prescribe licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for affiliate businesses and filing/process requirements for rate-setting purposes.

The *Ontario Energy Board Act, 1998* gave the OEB increased powers and responsibilities, including the power to approve or fix rates for the transmission and distribution of electricity, and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. In its approval to set rates, the OEB has the authority to specify regulatory treatments that may result in accounting treatments that differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Corporation's regulatory assets represent amounts receivable from customers in the future and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Corporation's regulatory liabilities represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

Since the commencement of Market Opening, HCHI and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator (the "IESO") and recovering the costs of electricity and certain other costs in accordance with procedures mandated by the OEB.

Pursuant to industry regulation, HCHI is required to be the default billing and collecting agent for all electricity related charges for all electricity participants, which, in addition to its own electricity distribution service charges, include:

- *Electricity Price and Related Rebates* – the commodity cost of electricity accruing to generators such as the provincially owned Ontario Power Generation Inc. ("OPGI"). The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan ("RPP"), which consists of a two-tiered pricing structure with seasonal thresholds. Customers that are not eligible for the RPP pay the market price for electricity, and receive an adjustment for the difference between the market price and set prices paid to certain regulated and contract generators.

- *Retail Network and Connection Transmission Rates* – wholesale costs incurred by distributors in respect of transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

- *Wholesale Market Service Charge* – wholesale market support costs charged to market participants such as the IESO fees and uplift charges. These charges are also regulated by the OEB.

- *Debt Retirement Charge ("DRC")* – provincial charge directed to the repayment of the stranded debt obligations of the former Ontario Hydro, which continue in the Ontario Electricity Financial Corporation (the "OEFC"), an agency of the Ontario government.

These other non-distribution charges represent "pass through" charges and the Corporation must remit them to other industry participants regardless of whether such charges are ultimately collected from customers. With the exception of DRC, electricity distribution companies are exposed to losses for entire amounts billed to customers.

As a market participant, HCHI is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of a letter of credit. The Corporation collects cash and cash equivalent deposits from certain customers and retailers of electricity to reduce credit risk. It is also the policy of the Corporation to discontinue service for non-payment of customer accounts.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario). However, the Corporation and each of its subsidiaries is a "municipal electric utility" ("MEU") for purposes of the payments in lieu ("PILs") regime contained in the *Electricity Act, 1998*. Accordingly, the Corporation makes payments in lieu of corporate income taxes

to the OEFC (to be applied against certain debt obligations of the former Ontario Hydro). Commencing in 2008, the Corporation provides for PILs using the asset and liability method. Under this method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes.

In addition to the oversight role of the OEB, and the market monitoring and coordination role of the IESO, the Ontario Power Authority (the "OPA") was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among others. The OPA is also responsible for coordinating the delivery and funding of conservation and demand management ("CDM") programs. In 2007 HCHI entered into agreements with the OPA to deliver OPA-funded CDM programs during the years from 2007 to 2010. All programs are fully funded by the OPA and, as at December 31, 2008 HCHI has spent in the order of $166,000 (2007 - $225,000) on these programs. During 2008, HCHI received in the order of $33,000 on account of management fees and bonuses earned with respect to the delivery of the 2007 programs.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely, and when combined with communications systems will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the smart meter entity that will oversee the collection and management of data. Local Distribution Companies (LDCs), including HCHI, are accountable for the development of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time of use ("TOU") rates that are presently voluntary.

HCHI's 2006 distribution rates, as directed by the OEB, provided for a modest initial investment in smart meters calculated on the basis of $0.30 per residential customer per month but allocated equally to all metered customers and recovered through their monthly service charge. This incremental smart meter funding continued to apply in 2007 and 2008 rates, and until such time as HCHI deploys its smart meter initiative, which is now scheduled to commence in July 2009, with an estimated capital investment by the Corporation in the order of $3.8 million.

Ontario's electricity utilities are presently investing substantial amounts of capital to replace aging infrastructure, deploy smart meters, connect new load, and maintain system reliability. If passed, Bill 150, the *Green Energy and Green Economy Act, 2009*, will further increase utility infrastructure investment. Ontario's electricity utilities will be charged with planning for and connecting renewable distributed electricity generation. They will also be given

responsibility to implement the smart grid and to take a lead role in creating a conservation culture through the implementation of CDM programs. Promoting conservation is a new guiding objective of the OEB, and CDM targets could now be made a condition of a distribution licence.

ELECTRICITY DISTRIBUTION RATES

In 2006 the OEB commenced a process of establishing an Incentive Regulation Mechanism ("IRM") multi-year electricity distribution rate-setting plan for the years 2007 to 2010. The objectives of the plan are to provide greater regulatory certainty to distributors during those years as several rate-related studies are carried out, to begin to drive efficiency improvements in the distribution sector, and to lay a foundation for 3rd Generation Incentive Regulation Mechanism ("3rd GIRM"). Incentive based regulation (also commonly known as Performance Based Regulation, or "PBR") is a regulatory methodology to encourage utility management to be efficient in the running of their business. Other key elements include developing a methodology, including benchmarking, for the comparison of distributor costs (a continuation of the former comparators and cohorts review), a comprehensive electricity distribution rate design review, and service quality regulation review.

The process includes a formulaic approach to establishing 2007 and subsequent rates with a rate rebasing approach to be staggered across all Ontario LDCs between 2008 and 2010. Rebasing is essentially a review of all utility costs, requiring the submission of a comprehensive full cost of service application based on a forward test year to set new distribution rates. The Corporation's ability to continue to maintain and operate the distribution system reliably and safely in the future will depend on, among other things, the OEB allowing recovery of costs in respect of the Corporation's maintenance program and capital expenditure requirements. HCHI is scheduled to rebase for rates to be effective in 2010, requiring this application process to commence in mid-2008 to achieve the filing deadline of no later than August 28, 2009 for rates to be effective May 1, 2010.

The approach for setting 2007 rates was based upon an OEB-approved formula that considered inflation less a productivity factor. The 2007 rate application model utilized existing Board-approved 2006 rate classifications, rates and charges. The approach for setting 2006 rates was based upon a rate of return/cost of service approach through the use of an adjusted 2004 historical test year, establishing the overall costs of service inclusive of PILs (net revenue requirement) to be recovered from customers through revised distribution rates. The 2006 rate application provided for a revised rate of return of 9.0% (compared to 9.88% in previous years). This net price cap adjustment was applied to the fixed and variable components of the base distribution rates, net of any incremental smart meter funding. In accordance with the OEB filing requirements, this application provided for a 0.90% increase to the distribution portion of the average residential bill.

For HCHI, the approach for setting 2008 rates continued on the basis of the 2nd generation IRM process. The first of a 3-year phased-in adjustment for the transition to a common deemed capital structure of 60% debt to 40% equity (currently 50:50) was also effected. In addition, a change in the federal income tax rate effective January 1, 2008 was incorporated into the rate model to be reflected in distribution rates. The rate rider associated with the recovery of regulatory assets ceased on May 1, 2008. The OEB also directed LDCs to provide for retail transmission rate adjustments as a result of a reduction in the uniform transmission rates for Ontario transmitters, effective November 1, 2007. In October 2007, HCHI filed its application for 2008 distribution rates, to be effective May 1, 2008. In accordance with these filing requirements, this application provided for a 2.88% decrease to the distribution portion of the average residential bill. The OEB issued its Decision on March 18, 2008 and Order on April 22, 2008 approving the applied-for tariff of rates and charges.

Similarly, the approach for setting 2009 rates will continue on this basis.

RESULTS OF OPERATIONS

Year Ended December 31, 2008 compared to Year Ended December 31, 2007

Revenues	***2008***	***2007***
Distribution Service Charges	$ 11,586,757	$ 11,791,098
Other Operating Revenue	$ 2,224,810	$ 1,249,510

Distribution Service Charges (referred to as "Gross Margin on Service Revenue" on the Consolidated Financial Statements.)

- Distribution revenues are primarily influenced by our distribution rates and the amount of electricity we distribute. Net distribution service revenues decreased in 2008 in the order of $204,000 as compared to last year primarily as a result of the net decrease between the two OEB-approved distribution rate adjustments (as explained above) that became effective May 1, 2007 and May 1, 2008. The volumetric (usage based) component of distribution revenue comprises approximately 71% of the total. Consumption decreased in 2008 to approximately 352 million kWh (2007 – 360 million kWh). The volume of electricity consumed by HCHI's customers during any given period is governed by events largely outside HCHI's control – primarily sustained periods of hot or cold weather, which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity. Accordingly, there can be no assurance that HCHI will earn the revenue requirement approved by the OEB.

- Revenue from the sale of electricity is recorded on the basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. The Corporation estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Services and other operating revenue are recognized as services are rendered.

Other Operating Revenue includes various sources of revenue as listed in Note 9 accompanying the Consolidated Financial Statements.

- Total other operating revenues increased in 2008 in the order of $975,000 as compared to last year.

- Interest earned accounted for most of this revenue increase. A cumulative adjustment calculated back to May 2002, in the order of $956,000, on account of the carrying charges associated with the OEB deferred regulatory asset accounts, was recognized during 2008. This increase was partially offset due to lower interest income from lower interest rates on cash balances during the year

- The Corporation continues to provide municipal water and sewer billing, collecting, and customer care services to the County. Pursuant to a formal agreement effective April 1, 2003, for the provision of these services between the County and the Corporation, this contract was renewed with a rate increase to $4.10 per bill effective April 1, 2008 ($3.98 effective April 1, 2007). Due to the nature of these services, the agreement is with HCEI, the non-regulated retail services subsidiary, which has further entered into an agreement with HCHI for the provision of these services on behalf of HCEI.

- As noted above, OPA CDM fees in the order of $33,000 on account of the 2007 programs were recognized in 2008.

- Miscellaneous income includes the long-term load transfer amounts received from Hydro One Networks Inc. and Norfolk Power Distribution Inc.

Expenses	***2008***	***2007***
Operating Expenses	$ 7,176,085	$ 7,278,641
Amortization	$ 2,453,156	$ 2,172,573
Interest Expense	$ 792,245	$ 878,326

Operating Expenses include Distribution, Billing and Collecting, General Administration and Directors. Similar to 2007, expenditures necessary to operate and maintain the distribution system were budgeted to increase during 2008, however they were both slightly lower than the forecasted total as well as compared to 2007.

Significant operating activities, including departmental projects contributing to these expenses, include the following:

- HCHI continued with its Distribution System Maintenance and Inspection program in 2008. HCHI remains focused on reliability while recognizing the challenges in operating a distribution system with low customer density and rural geography. Maintenance was carried out while also managing the impact of disturbances. Significant maintenance activities included maintaining Canfield Distribution Station and the addition of the inspection of off road distribution lines only accessible by track mounted aerial equipment.

- HCHI has committed to the identification and removal of PCB contaminated transformers from its distribution system. In 2008, 21 of these transformers were removed from service. This removal activity will continue over the next five to ten year period, and will eliminate PCBs from HCHI's service territory.

- The OEB regulates plant inspections as a requirement for all LDCs. HCHI's program this year concentrated on the five urban community centres within Haldimand County. This work includes the immediate repair of deficiencies accessible from the ground, wood pole integrity testing where required, and capturing GPS coordinates for each pole location. Major deficiencies are noted for further engineering work and the GPS coordinates are used to plot each pole on HCHI's mapping and geographical information system (GIS). This GIS system, when fully populated, will enable future enhancements in HCHI's asset management strategy. As of the 2008 year-end this program has identified and documented approximately 13,500 poles.

- As part of a five-year cycle, line clearing of trees continued in 2008. This work concentrated on the former townships of Canborough, Moulton, and Sherbrooke. Other areas where outages were more frequent than average were also cleared. This program continues to be very effective in reducing tree-related power interruptions.

- HCHI currently has seven distribution substations (DSs) and one regulating station (RS) in service, most of which are approaching 50 years of age and nearing their end of life expectancy. As part of the Corporation's long-term plan to remove DS's from service by converting the service territory to 27.6 kV, Nanticoke DS was permanently removed from service in late 2008 (part of 2008's capital projects). As stations are removed from service the sites are

screened for contaminants and remediated accordingly. Environmental remediation of the former Rainham DS site on Fisherville Road was completed in late 2007 and sale of the property closed on June 5, 2008. Also in 2008 the former Forest DS site in Dunnville was remediated and is expected to be disposed of in 2009. This leaves one DS in Hagersville and one DS in Nanticoke for future testing and potential remediation.

- Transformer gas and oil analysis on all substation transformers was completed as part of the annual maintenance program. Of the 10 transformers tested, 9 require additional testing to determine if ongoing issues are present. A number of these units will require oil processing in 2009 to maintain the integrity of the transformers.

- In 2006 HCHI embarked on an effort to recycle and rebuild transformers to fulfill current and future requirements; that is, using parts of old units to build new units. This program continues to lower the purchase cost of transformers (compared with new units) and promotes environmental stewardship as it reuses materials that would normally enter the waste stream.

- The potentially hazardous nature of our business requires a strong focus on safety, which continued to be a top priority in 2008. HCHI's focus in 2008 was to begin development of a hazard recognition and risk assessment program. Pilot projects were completed by year's end and the formal program will be rolled out in 2009. Once complete this program will represent a significant milestone in HCHI's Health and Safety program.

- HCHI is committed to correcting parts of the distribution system which present potential safety concerns to the public. A number of hazards were recognized and rectified in 2008. The largest of which was the removal of approximately 7 kilometres of off-road pole line, which was taken out of service by the former Nanticoke Hydro-Electric Commission and had fallen into disrepair.

- Copper theft has been an ongoing issue for electric utilities for the last several years. In the last couple of years elevated scrap copper prices have only made the situation worse. In July, 2008 HCHI experienced its first theft of copper issue that affected its electrical supply to customers when copper was cut from the Canfield DS causing voltage stability issues. The problem was readily corrected but added unnecessary expense to HCHI's operating costs.

The Corporation employed 46 full-time employees as at the end of 2008 (2007 – 46), for a combined gross payroll, including employer portions of source deductions and employee group health benefit premiums in the order of $3.6 million (2007 - $3.3 million).

- There were no new staff positions created during 2008 (2007 – 2). There were two vacancies created in Customer Service due to resignations, both of which were filled during the year. A vacancy created in Engineering as a result of a retirement was also filled during the year.

- Increased payroll costs are a function of the 4% across the board wage increase effective April 1, 2008. The bargaining unit employees are represented by the International Brotherhood of Electrical Workers ("IBEW") Union. The existing 39-month collective agreement expired on March 31, 2009 and collective bargaining commenced in the spring of 2009.

Amortization expense increased in 2008 in the order of $281,000 over 2007 (2007 increased $136,000 over 2006).

- This increase is attributable to the placement of new assets in service, consistent with our ongoing capital works program including new projects, services, line extensions, routine replacement and enhancements of aging infrastructure, tools, shop and transportation equipment, and general administrative assets, net of capital contributions, in the order of $4.6 million (2007- $2.9 million).

- In 2008, net capital expenditures provided for the rebate of capital contributions, in the order of $57,000 (2007- $140,000), to developers on account of eligible subdivision agreements entered into after November 2000. The rebates are calculated using an economic evaluation model developed in accordance with the OEB's Distribution System Code.

Capital Expenditures Net of Capital Contributions

	2008	**2007**
Distribution Plant Assets	$ 3,714,756	$ 1,819,951
Tools, Shop and Transportation Equipment	$ 102,398	$ 124,940
General Administration Assets	$ 811,410	$ 953,234
Sentinel Light Rental Units	$ 6,080	$ 4,333
Total	**$ 4,634,644**	**$ 2,902,458**

- General Administration Assets in 2008 include the development, configuration, testing and training costs associated with the Customer Information System ("CIS") conversion from the Advanced Utility Billing CIS to the Harris Computer Systems Northstar CIS, which commenced in March 2008 in preparation for a March 1, 2009 "go live" implementation.

Interest expense decreased in 2008 in the order of $86,000 over 2007 (2007 decreased $51,000 over 2006).

- This is consistent with the increase in the scheduled long-term liabilities' principal repayments during the year in the amount of $1,021,000 (2007 - $988,000), as well as lower interest rates on the CIBC demand loan.

- The Corporation's primary sources of funding for capital expenditures are cash provided by operating activities, interest income and debt financing. The Corporation expected additional debt financing to be required during 2008 and entered into an Ontario Infrastructure Projects Corporation ("OIPC") loan application in the fall of 2008. Approval for the OIPC loan application was obtained in April 2009 with the first draw down of funds on May 1, 2009.

Results of Operations	***2008***	***2007***
Revenues	$ 13,811,567	$ 13,040,608
Expenses	$ 10,421,486	$ 10,329,540
Income Before Income Taxes	$ 3,390,081	$ 2,711,068
Income Taxes	$ 1,326,849	$ 912,560
Net Income	$ 2,063,232	$ 1,798,508

The overall increase in total revenues in 2008 in the order of $771,000, combined with the increase in total expenses in 2008 in the order of $92,000 over 2007, resulted in a net increase in net income before income taxes for the year. After providing for an increase in income taxes, and in particular future income taxes, net income in 2008 increased in the order of $265,000.

Funds Generated from Operations

Cash and cash equivalents decreased to $3.6 million in 2008 (2007 - $5.4 million). The significant increase in cash flows from operating activities was offset by the increases in investing in capital assets, financing activities including long-term debt repayments and regulatory assets.

Related Party Transactions

The Corporation's operations include the provision of electricity and services to its sole Shareholder. Electrical energy is sold to the County at the same prices and terms as other electricity customers in their rate class. Street lighting maintenance services are provided at cost. Water and sewer billing, collecting, and customer care services are provided pursuant to the agreements mentioned earlier, at rates based on the average cost to provide this service.

A summary of the reciprocal charges between the Corporation and the County is provided below.

Summary of Reciprocal Charges between the Corporation and the County

Amounts Billed by the Corporation To the County	**2008**	**2007**
Electrical Energy	$ 1,718,382	$ 1,750,796
Distribution Services portion of Electrical Energy actually retained by HCHI	$ 320,380	$ 292,207
Street Lighting Maintenance	$ 122,858	$ 64,606
Water and Sewer Billing & Collecting	$ 418,623	$ 402,668
Tree Trimming and Removals	$ 20,132	$ 12,455
Supply and Install Banner Pole Structures	$ 0	$ 25,196
Supply, install and relocate poles – various locations	$ 9,823	$ 0
Isolation at Caledonia Satellite Office	$ 782	$ 0
Amounts Billed by the County To the Corporation		
Property Taxes	$ 48,631	$ 49,215
Bank Service Charges – Debenture Handling	$ 1,278	$ 5,176

Dividends

Dividends on common shares are declared at the discretion of the Board of Directors – subject to applicable law and based on direction from the Shareholder, the Board's proposed dividend policy, and recommendations of Management - with consideration for results of operations, financial condition and future outlook, cash requirements and industry practice.

The Corporation declared and paid dividends in the amount of $449,627 in 2008 (2007 - $404,452) for total dividends paid to date since 2003 in the amount of $1,850,309 to its sole Shareholder, Haldimand County.

Consistent with the Board's proposed dividend policy of paying dividends based on 25% of the previous year's net income, on April 22, 2009 the Board of Directors of the Corporation declared dividends in the amount of $515,808 to be paid in 2009.

The book value of the County's original investment of $19.1 million in 2000 has increased in the order of $9.7 million to $28.8 million as a result of operations, net of dividends paid to date, to the end of 2008.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying Consolidated Financial Statements of the Corporation, prepared in accordance with Canadian generally accepted accounting principles, including accounting principles prescribed by the OEB, are the responsibility of Management and have been approved by the Board of Directors (the "Board"). The significant accounting principles, including regulatory treatments, are disclosed in Note 2 to the Consolidated Financial Statements.

Fulfilling this responsibility requires the preparation and presentation of consolidated financial statements and other data which necessarily involves the use of estimates and assumptions based on management's best judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered. Management has exercised careful judgment where estimates were required; however, due to the 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, the Minister of Energy or the Minister of Finance. Accordingly, these Consolidated Financial Statements reflect all information available to March 3, 2009.

The Consolidated Financial Statements have been examined by Millard, Rouse & Rosebrugh, LLP, Licensed Public Accountants, external auditors of the Corporation. The Auditor's report, which accompanies these statements, outlines the scope of their audit examination and states their opinion.

Management maintains appropriate systems of internal controls designed to provide reasonable assurance that the assets of the Corporation are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and timely. The internal control systems include formal corporate-wide policies and procedures and an organizational structure that provides a proper delegation of authority and segregation of responsibilities.

The Board, through the Audit and Finance Committee, is responsible for ensuring that Management fulfils its responsibility for financial reporting, accounting systems and internal controls. The Audit and Finance Committee, which is comprised of the same Directors as the Corporation, meet with Management and the external auditors to review the Consolidated Financial Statements and recommends their approval to the Board.

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2008

HALDIMAND COUNTY UTILITIES INC.

For the year ended December 31, 2008

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AUDITORS' REPORT

To the Shareholder of
Haldimand County Utilities Inc.

We have audited the consolidated statement of financial position of Haldimand County Utilities Inc. as at December 31, 2008 and the consolidated statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company'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 consolidated financial statements present fairly, in all material respects, the financial position of Haldimand County Utilities Inc. as at December 31, 2008 and the consolidated results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

March 3, 2009

CHARTERED ACCOUNTANTS
Licensed Public Accountants

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31	2008	2007
ASSETS		
Current Assets		
Cash and bank	3,591,339	5,385,329
Unbilled revenue	4,062,384	3,952,354
Accounts receivable	2,823,972	2,332,081
OPA conservation program	-	92,366
Inventory	918,765	1,328,030
Income taxes recoverable	204,141	543,637
Prepaid expenses	284,201	62,221
	11,884,802	13,696,018
Property, Plant and Equipment (Note 5)	35,102,601	32,558,018
Deferred Financing Costs	12,941	22,647
Regulatory Assets (Note 6)	728,070	-
Future Tax Asset	717,886	-
	48,446,300	46,276,683
LIABILITIES		
Current Liabilities		
Accounts payable and accrued expenses	5,619,678	5,015,698
OPA conservation program	45,133	-
Future income taxes	-	5,951
Current portion of long term liabilities	3,840,829	2,002,905
	9,505,640	7,024,554
Regulatory Liabilities (Note 6)	-	480,776
Long Term Liabilities (Note 7)	7,860,738	10,702,459
	17,366,378	18,207,789
Deferred Credits		
Contributions in aid of construction	2,676,419	2,434,207
Less: Amortization to date	427,196	326,089
	2,249,223	2,108,118
SHAREHOLDER'S EQUITY		
Capital (Note 8)	20,289,812	20,289,812
Retained Earnings (Page 3)	8,540,887	5,670,964
	28,830,699	25,960,776
	48,446,300	46,276,683

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2008	2007
Retained Earnings - Beginning of Year	5,670,964	4,276,908
Adjustment for future income taxes (Note 3)	1,256,318	-
Retained Earnings - Adjusted	6,927,282	4,276,908
Net income	2,063,232	1,798,508
Dividends	(449,627)	(404,452)
Retained Earnings - End of Year	8,540,887	5,670,964

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF INCOME

For the year ended December 31	2008	2007
Service Revenue		
Residential	11,979,437	12,861,238
General	8,216,593	8,277,577
Street lighting	146,066	151,591
Distribution services	11,651,675	11,862,512
	31,993,771	33,152,918
Service revenue adjustment	431,294	286,649
	32,425,065	33,439,567
Cost of Power	20,838,308	21,648,469
Gross Margin on Service Revenue	11,586,757	11,791,098
Other Operating Revenue (Note 9)	2,224,810	1,249,510
	13,811,567	13,040,608
Expenses		
Distribution, operation and maintenance (Note 10)	3,896,996	4,065,584
Community relations	38,718	123,846
Billing and collecting	1,308,270	1,281,272
General Administration	1,855,430	1,721,723
Directors	76,671	86,216
	7,176,085	7,278,641
Amortization	2,554,263	2,256,755
Less: Amortization of contributions in aid of construction	101,107	84,182
	2,453,156	2,172,573
	9,629,241	9,451,214
Income Before Interest and Income Taxes	4,182,326	3,589,394
Interest expense	792,245	878,326
Income Before Income Taxes	3,390,081	2,711,068
Income taxes - current (Note 11)	794,368	915,776
- future	532,481	(3,216)
Net Income	2,063,232	1,798,508

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31	2008	2007
Cash Flows from Operating Activities		
Net Income	2,063,232	1,798,508
Charges (credits) to income not involving cash		
Amortization	2,554,263	2,256,755
Amortization allocated as overhead	-	120,219
Amortization of contributions in aid of capital	(101,107)	(84,182)
(Gain) loss on disposal of property, plant and equipment	(23,778)	(3,317)
Future income taxes	532,481	(3,216)
	5,025,091	4,084,767
Net change in non-cash working capital balances related to operations	666,339	(131,835)
	5,691,430	3,952,932
Cash Flows from Financing Activities		
Dividends	(449,627)	(404,452)
Deposits from customers (net)	17,203	(188,812)
Contributions in aid of construction	242,212	472,830
Long term debt	(1,021,000)	(987,667)
Deferred financing costs	9,706	9,706
	(1,201,506)	(1,098,395)
Cash Flows from Investing Activities		
Purchase of property, plant and equipment	(5,131,254)	(3,385,648)
Proceeds on disposal of property, plant and equipment	56,186	6,617
Regulatory assets/liabilities	(1,208,846)	(418,771)
	(6,283,914)	(3,797,802)
Net Decrease in Cash and Cash Equivalents	(1,793,990)	(943,265)
Opening Cash and Cash Equivalents	5,385,329	6,328,594
Closing Cash and Cash Equivalents	3,591,339	5,385,329

See accompanying notes

HALDIMAND COUNTY UTILITIES INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the year ended December 31, 2008

1. NATURE OF ACTIVITIES

Haldimand County Utilities Inc. ("the Company") was incorporated under the Ontario Business Corporations Act on October 13, 2000. The Company acts as the holding company for the shares of Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

(a) Basis of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries: Haldimand County Hydro Inc., Haldimand County Energy Inc., and Haldimand County Generation Inc.

(b) General

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the Ontario Energy Board under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the Ontario Energy Board Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles.

(c) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations.

(d) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

(e) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at their historical cost. Amortization is calculated on a straight-line basis over the estimated useful service life as follows:

Buildings	50 years	Distribution stations	30 years
Distribution lines - overhead	25 years	Distribution lines - underground	25 years
Distribution transformers	25 years	Distribution meters	25 years
Rolling stock	8 years	Sentinel lights	10 years
Other capital assets	5 - 50 years		

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Contributions in Aid of Construction

Contributions in aid of construction are reported as deferred credits and amortized over the useful life of the related property, plant and equipment. Contributions prior to 2000 are included in equity as contributed capital.

(g) Revenue Recognition

Distribution revenues are based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on the electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

(h) Payments in Lieu of Corporate Income Taxes

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

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

(i) Financial Instruments

Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows:

1. Cash and bank are classified as Held for Trading and measured at fair value.
2. Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method..
3. Accounts Payable, amounts due to affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.
4. Purchases and sales of financial instruments are accounted for at trade date.
5. Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of CICA Handbook section 3861 rather than Handbook sections 3862 and 3863.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(j) Regulatory Policies

The Company has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.

2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. CHANGE IN ACCOUNTING POLICIES

On January 1, 2008 the Company adopted the following new Canadian Institute of Chartered Accountants (CICA) Handbook Sections: Section 1535 "Capital Disclosures" and Section 3031 "Inventories".

Section 1535 requires the Company to disclose information about its capital and how it is managed. It requires the disclosure of qualitative and quantitative information about the company's objectives, policies and processes for managing capital and whether the Company has complied with any externally imposed capital requirements.

Section 3031 replaced the previous inventory section and established revised standards for the measurement of inventory, allocation of overhead, accounting for impairment in inventory value and financial statement disclosure.

There was no effect on the comparative financial statements as a result of adopting these new standards.

On January 1, 2008 Haldimand County Hydro Inc. adopted the policy of recording future income taxes, converting from the taxes payable method previously used. This change in policy was recorded prospectively without an adjustment to prior year's figures.

Future Accounting Changes

In 2008, the Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. The Company is actively monitoring the transition to IFRS and is analyzing the impact that IFRS will have on its financial statements.

The AcSB has removed a temporary exemption in the CICA Handbook Section 1100 "Generally Accepted Accounting Principles" which permits the recognition and measurement of assets and liabilities arising from rate regulation. The CICA has issued an accounting guideline (AcG-19) to provide guidance for rate regulated entities. This change will be effective relating to fiscal years beginning on or after January 1, 2009. The Company is continuing to assess and monitor any additional implications on its financial statements.

4. RATE SETTING

The rates of the company's electricity distribution business is subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Haldimand County Hydro Inc. and remitted to the IESO. The Company retains the distribution charge on the customer hydro invoices. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 6.

Haldimand County Hydro Inc.'s approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective May 1, 2008, were calculated on a 2004 rate base and included a rate of return on equity of 9.0%.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2008	2007
Land	139,071	-	139,071	160,824
Buildings	1,993,907	270,056	1,723,851	1,687,067
Distribution stations	580,903	211,925	368,978	185,715
Distribution lines - overhead	23,707,543	8,209,698	15,497,845	13,929,628
Distribution lines - underground	6,941,095	2,465,472	4,475,623	4,584,999
Distribution transformers	11,961,649	3,366,958	8,594,691	8,013,086
Distribution meters	2,744,748	850,198	1,894,550	1,915,295
Sentinel lights	171,950	152,894	19,056	23,843
Rolling stock	1,185,427	841,028	344,399	414,137
Other capital assets	3,845,497	1,800,960	2,044,537	1,643,424
	53,271,790	18,169,189	35,102,601	32,558,018

6. REGULATORY ASSETS (LIABILITIES)	2008	2007
Deferred payments in lieu of taxes	985,885	875,656
Retail settlement variance accounts	16,708	(925,322)
Recovery of regulatory asset balances	(138,483)	(347,219)
Deferred pension costs	203,428	196,330
Smart meters	(36,956)	(12,268)
Low voltage services	(302,512)	(267,953)
	728,070	(480,776)

The deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

On April 12, 2006, the OEB announced its decision regarding the company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account (RAR). The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2004.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

7. LONG TERM LIABILITIES	2008	2007
Non-callable debenture, with graduated interest rates starting at 6% in 2000, up to 6.5% in 2010. Interest is payable semi-annually, principal is payable annually. Due May 1, 2010	8,180,000	8,660,000
Non-callable debenture, with graduated interest rates starting at 5.25% in 1999, up to 6.125% in 2009. Interest is payable semi-annually, principal is payable annually. Due July 2, 2009	2,485,000	2,826,000
Prime minus 0.6% CIBC demand loan repayable in monthly instalments of $16,667 plus interest. Due December 2011	600,000	800,000
Customer Deposits	436,567	419,364
	11,701,567	12,705,364
Current portion	3,840,829	2,002,905
	7,860,738	10,702,459

7. LONG TERM LIABILITIES (continued)

Based upon current repayment terms, the estimated annual principal repayments and return of customer deposits are as follows:

2009	-	3,440,829
2010	-	7,895,884
2011	-	229,184
2012	-	25,376
2013	-	53,223

The CIBC demand instalment loan is secured by a general security agreement on all property owned by the Company. The debentures are payable to The Corporation of Haldimand County on behalf of the former Region of Haldimand-Norfolk.

8. CAPITAL	**2008**	**2007**
Capital Stock		
Authorized - an unlimited number of common shares		
Issued - 1,001 common shares	19,149,049	19,149,049
Miscellaneous Paid-in Capital	1,140,763	1,140,763
	20,289,812	20,289,812

9. OTHER OPERATING REVENUE	**2008**	**2007**
Late payment charges	55,173	61,049
Retail service charges	32,359	38,068
Sentinel light rental	90,157	90,868
Interest earned	1,038,496	117,001
Pole rentals	72,444	69,495
Change of occupancy charges	71,550	80,540
Collection charges	237,270	221,142
Reconnection charges	56,945	65,290
Profit on sale of material services	13,868	23,761
Water and sewer billings	418,623	402,668
Gain (loss) on disposal of property, plant and equipment	23,778	3,317
Ontario Power Authority CDM fees	32,680	-
Miscellaneous	81,467	76,311
	2,224,810	1,249,510

10. DISTRIBUTION, OPERATION AND MAINTENANCE	2008	2007
Distribution station equipment	260,124	239,442
Overhead distribution lines	2,257,635	2,565,730
Underground distribution lines	224,703	138,549
Distribution transformers	346,170	438,060
Distribution meters	244,482	220,067
Distribution supervision and engineering	549,351	447,761
Sentinel light maintenance	14,531	15,975
	3,896,996	4,065,584

11. INCOME TAXES - CURRENT	2008	2007
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income before income taxes	3,390,081	2,711,068
Amortization in excess of Capital Cost Allowance	193,694	277,669
Net change in regulatory assets	(1,208,846)	(418,771)
(Gain) Loss on disposal of assets	(23,778)	(3,317)
Other additions and deductions	46,824	7,821
Taxable income	2,397,975	2,574,470
Tax at 33.13%, (2007 - 36.06%)	794,368	915,776

12. RELATED PARTY TRANSACTIONS

The Company is wholly owned by The Corporation of Haldimand County. Haldimand County Utilities Inc. owns 100% of Haldimand County Hydro Inc., Haldimand County Energy Inc. and Haldimand County Generation Inc. Transactions between Haldimand County Hydro Inc., Haldimand County Energy Inc., Haldimand County Generation Inc., and Haldimand County Utilities Inc. occur in the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

13. PRUDENTIAL SUPPORT

Haldimand County Hydro Inc. is required, through the IESO, to provide security to mitigate the company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Haldimand County Hydro Inc. fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2008, the Company provided prudential support in the form of bank letters of credit of $2,115,330. The letters of credit are secured by a general security agreement on all property owned by the Company.

14. CAPITAL MANAGEMENT

The company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The company's total capital as at December 31, consists of:

	2008	2007
Total long term liabilities	11,701,567	12,705,364
Less: cash and bank	3,591,339	5,385,329
Net long term liabilities	8,110,228	7,320,035
Total shareholder's equity	28,830,699	25,960,776
Total capital	36,940,927	33,280,811

15. FINANCIAL INSTRUMENTS

Management and the Board monitor and respond as necessary to any risks arising from financial instruments.

Fair Value

The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and accounts payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Interest Rate Risk

The company's exposure to interest rate risk relates to its floating bank rate indebtedness (see Note 7).

Credit Risk

The company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers in accordance with direction provided by the OEB. The Company held deposits of $436,567 at year end in order to mitigate credit risk.

16. LATE PAYMENT PENALTIES

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 proceedings 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 and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the Ontario Energy Board ("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. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

Other
A claim has been filed against the Company for recovery of a claim filed against the former Ontario Hydro. The claim related to stray voltage. At this time, it is not possible to quantify the effect, if any, of this claim on the financial statements of the Company, consequently no provision for a loss, if any, has been recorded in these financial statements.

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
	1			**Overview**
		1		Rate Base Overview
		2		Variance Analysis on Rate Base Table
	2			**Gross Assets – Property, Plant and Equipment and Accumulated Amortization**
		1		Continuity Statements
		2		Gross Assets Table
		3		Variance Analysis on Gross Assets including Assignment of Capital Projects to USoA
		4		Accumulated Amortization Table
		5		Variance Analysis on Accumulated Amortization
	3			**Capital Budget**
		1		Asset Management Plan Summary
			A	Distribution Asset Management Plan
		2		Capitalization Policy
	4			**Allowance for Working Capital**
		1		Overview and Calculation by Account

RATE BASE

Rate Base Overview

The rate base used for the purpose of calculating the revenue requirement used in this Application follows the definition used in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2010 Test Year, plus a working capital allowance, which is 15% 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. Haldimand County Hydro Inc's ("HCHI") rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

HCHI has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year in Table 1 below. HCHI has calculated its 2010 rate base as $40,097,055.

Table 1
Summary of Rate Base

Description	2006 OEB Approved	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Gross Fixed Assets	37,474,735	42,892,325	45,728,619	50,423,422	54,852,521	58,164,822
Accumulated Depreciation	7,639,543	13,088,866	15,302,560	17,589,099	20,403,075	23,335,161
Net Book Value	29,835,192	29,803,460	30,426,058	32,834,323	34,449,446	34,829,661
Average Net Book Value	29,402,632	29,386,766	30,114,759	31,630,191	33,641,885	34,639,553
Working Capital	32,014,592	34,269,497	35,678,413	34,344,561	35,781,987	36,383,347
Working Capital Allowance	4,802,189	5,140,425	5,351,762	5,151,684	5,367,298	5,457,502
Rate Base	34,637,381	34,527,190	35,466,521	36,781,875	39,009,183	40,097,055

HCHI has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2006

Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year in Table 2, below. Details of HCHI's calculation of its working capital allowance are provided at Exhibit 2, Tab 4, Schedule 1, below.

Table 2
Summary of Working Capital Calculation

Description	2006 OEB Approved	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Cost of Power	26,512,482	28,689,182	28,516,480	27,256,106	28,285,218	28,677,930
Operations	937,061	1,158,902	1,193,191	1,222,063	1,386,280	1,437,648
Maintenance	1,697,967	1,430,796	2,856,418	2,660,402	2,767,244	2,802,733
Billing & Collecting	1,096,343	1,246,221	1,278,655	1,303,979	1,355,335	1,403,423
Community Relations	28,034	85,931	123,846	38,719	45,972	46,836
Administration & General Expense	1,688,118	1,606,856	1,657,712	1,811,769	1,890,001	1,961,330
Property Taxes	54,587	51,609	52,111	51,523	51,937	53,447
Working Capital	32,014,592	34,269,497	35,678,413	34,344,561	35,781,987	36,383,347

Haldimand County Hydro Inc. Distribution System

HCHI owns and operates the electricity distribution system in its licensed service area in Haldimand County, serving approximately 20,840 Residential, General Service, Street Lighting, Sentinel Light and Unmetered Scattered Load customers and two Embedded Distributors, as at June 30, 2009.

HCHI is supplied through the Hydro One Networks Inc. ("HONI") transmission system from 3 transformer stations at a primary voltage of 27.6 kV. Electricity is then distributed through HCHI's service area, 1,252 km^2, over 83 road km of underground cable and 1,570 road km of overhead primary conductor. HONI also owns 87 road km of distribution line in Haldimand County that serves HCHI's customers. Primary voltage is stepped down through 6 HCHI-owned distribution stations and 2 HONI-owned distribution stations to service General Service and Residential customers. Voltage is

stepped down from the 27.6 kV, 8.32 kV, and 4.16 kV primary feeders through approximately 7,229 LDC owned distribution transformers.

HCHI owns and maintains approximately 20,760 meters (as at June 30, 2009) installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW and kVA demand as well as hourly interval data. HCHI is expected to have full deployment of its smart meters by December 31, 2009 as part of the Province of Ontario's smart meter initiative. On June 25, 2008, Ontario Regulation 235/08 was filed by the Ontario Provincial Government giving Haldimand County Hydro Inc. authorization to proceed with its Advanced Metering Infrastructure (AMI) Network. In accordance with the OEB's *"Smart Meter Funding and Cost Recovery Guideline (G-2008-002)"* issued October 22, 2008, HCHI is requesting a utility specific smart meter funding adder with this cost of service rate application with the anticipation that HCHI will apply for full recovery of its smart meter costs in the near future with a smart meter cost recovery application. Exhibit 9, Tab 2, Schedule 3 provides full details of the utility specific smart meter funding adder.

In managing its distribution system assets, HCHI's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service requirements. This Application incorporates HCHI's 2010 Capital and Expense Budgets in determining the revenue requirement to bring these objectives to fruition. Further information will be provided later in this Application. HCHI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the system.

HCHI 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 by account for the each actual year, the bridge year, and the test year was broken down by project in Exhibit 2, Tab 2, Schedule 3.

The projects in HCHI's five year capital plan and any new projects, which have arisen throughout the year, are evaluated for potential inclusion in the current year's project priorities. The following factors and sub-factors are considered:

1. Financial
    - Reduction of future operating costs
    - Elimination of sub-transmission charges
    - Reduction of losses
2. Reliability
    - Impact to SAIDI, SAIFI, and power quality (low voltage, etc.)
3. Safety
    - Public
    - Staff
4. Customer Relations
    - Impact / effect on customers
5. Regulatory
    - Compliance with regulatory statutes
6. Environmental
    - Elimination of risk of contamination to the environment – oil spills

Once priorities are decided, a preliminary project plan for each capital project is detailed on an individual project sheet complete with a map of the project site, description of project, and estimated costs. The estimated costs may be based on a detailed project design plan or a preliminary design plan. In terms of distribution system projects HCHI will be implementing a new model for prioritizing discretionary projects (does not include sustainment projects) starting in 2009. This model was developed by Kinectrics Inc. and senior HCHI management staff in the fall of 2008. It has been used to model all

2009 and 2010 discretionary projects. Details of the development, implementation, and description of 2009 and 2010 projects in terms of the model are covered in HCHI's Distribution Asset Management Plan (DAMP), Exhibit 2, Tab 3, Schedule 1, Appendix A.

In conjunction with the above capital project process and the budgeting process all members of the management team prepare detailed outlines of their recommendations for capital purchases, which are then discussed by the full group. After examining all recommended capital purchases they are listed in order from higher to lower priority and then moved forward based on appropriate financial parameters. This process occurs annually.

In addition to the capital needs of the distribution system, HCHI provides for maintenance planning and inspection for the assets. This is described in HCHI's Distribution System Maintenance and Inspection Program procedure (Appendix C of the Distribution Asset Management Plan). The same preparation and consideration steps are undertaken before the Finance Department prepares annual budget reports. Further information on HCHI's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

HCHI assets fall into two broad categories – distribution system plant, which includes assets such as overhead and underground electricity distribution infrastructure (i.e. poles, conductors, transformers, meters, substations, etc.); and general plant which includes assets such as buildings, building fixtures, computer systems, software, transportation equipment and tools. More detailed lists of distribution and general plant categories can be found in the Gross Assets Table at Exhibit 2, Tab 2, Schedule 2.

There are many reasons for initiating a project. HCHI has determined a number of primary drivers for projects that categorize the expenditure. In some cases there may be secondary drivers that also impact the reasons for initiating the project. Descriptions of primary drivers are listed below.

- **Customer Demand**

These are projects that HCHI undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and HCHI's Conditions of Service. Activities include connecting new customers, installing capacity to meet the growth needs of existing customers, building new subdivisions. Capital contributions toward the cost of these projects are collected by HCHI in accordance with the DSC and the provisions of its Conditions of Service. HCHI uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are included in the annual capital budget.

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new feeders, upgrade to conductors and transformers, voltage conversion projects, and upgrades to substations. These distribution projects are not customer-specific, but rather, they benefit many customers.

- **Sustainment**

Sustainment projects are completed when existing assets reach their end of useful life and must be replaced. HCHI completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and if warranted replace assets based on these inspection and testing activities. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public and staff.

- **Hazard**

The inspection and maintenance program identifies hazards in the distribution system. Generally these hazards involve clearance issues from lines to private buildings and

structures. Distribution system projects with this designation are designed to eliminate the hazard.

- **Municipal**

Road construction projects often involve the relocation of existing assets or the opportunity to install underground distribution assets in areas serviced by rear lot or front lot overhead distribution. The cost of the relocations is shared between the road authority and the utility.

- **Reliability**

The main driver for these investments is an analysis of what measures could be undertaken to improve HCHI's reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of HCHI's distribution system. These activities will support maintaining or improving the Service Quality Indices measured and submitted to the OEB each year by HCHI. Examples of this are primary fault indicators, which help identify faulted sections of the distribution system, devices which help reduce damages to the system, such as reclosers and lighting arrestors, creating backup feeders or lines to increase the flexibility of switching to enable a reduction in the duration of outages, and to improve low voltage situations which may occur during peak loading situations. The Distribution Asset Management Plan (DAMP) and the Asset Condition Assessment (ACA) provided in Exhibit 2, Tab 3, Schedule 1, Appendix A, support the capital and maintenance programs needed to maintain and enhance the reliability of HCHI's distribution system.

- **Regulatory Requirements**

These projects are system capital investments, which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment. From 2004 into

2008 there are a number of projects associated with eliminating long-term load transfers pursuant to the DSC.

- **Substations**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. Many of HCHI's substations are at or are approaching the end of life. A strategic decision has been made to replace the capacity of these stations with capacity on the 27.6kV distribution system. Converting 8.3kV lines and equipment to 27.6kV eliminates the need to maintain and sustain existing stations. When conversion to 27.6kV distribution is not compatible with the remaining life of a substation then capital replacement of the station components (usually the transformer) is undertaken. HCHI's strategy affecting substations is discussed in more detail in the DAMP.

- **Carryover**

Budgeted capital projects are usually (unless otherwise scheduled for multiple years) intended to be completed in the calendar year. However, there are projects which do not get completed in the calendar year and have costs allocated to them in subsequent years. When a project is carried over from one year to the next it is not re-budgeted in the following year. The costs are noted in the financial reports as "balance carried forward" from a given capital budget year. The reasons for not completing a project in the calendar year are among the following:

- Resources are not available to construct project
- Equipment procurement is delayed
- Project scope changes
- Weather slows or delays construction
- Municipal permits delayed

- **Wholesale Connections and Metering**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. HCHI is anticipating full deployment of its' AMI Network by December 31, 2009, as approved by Ontario Regulation 235/08 (Authorized Discretionary Metering Activity & Procurement).

HCHI capital projects for the 2010 Test Year are discussed in further detail below. HCHI has provided project-specific justifications in Exhibit 2, Tab 2, Schedule 3. Similarly, written explanations have been provided for rate base related variances that exceed materiality of $53,080 (0.5% of distribution revenue requirement; the materiality threshold required to be used as outlined in Chapter 2 of the updated OEB Filing Requirements dated May 27, 2009).

Gross Assets – Property, Plant and Equipment and Accumulated Amortization

The 2009 Bridge and 2010 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. These programs are described in detail in HCHI's written evidence at Exhibit 2, Tab 2, Schedule 3, Appendix A. Forecasted capital spending for the two subsequent years, 2011 and 2012, has been outlined in the DAMP. It should be noted that not all projects for 2011 and 2012 have been defined.

The following comments provide an overview of HCHI'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 prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

- **Responsibilities**

  - It is the responsibility of the Finance Manager to coordinate the development of the processes for the operating budget, the capital budget and forecasts.
  - Each department Manager is responsible for preparing its operating budget, capital budget and forecasts.
  - The President & CEO, with assistance from the Senior Management Team, is responsible for presenting and recommending the budget to the Board of Directors for approval.
  - It is the responsibility of the Board of Directors to approve the budget.

The budget is an important planning tool for HCHI. It puts capital and operating plans into a common financial plan. The final document provides a comprehensive package of department budgets that collectively ensure that appropriate resources are designated for the various capital and operating 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. HCHI notes that these Budget Plans address both capital and operating requirements. It is also important to communicate that these budgets are in fact plans that have some uncertainty and may need to be altered depending on events and circumstances arising throughout the budget year.

RATE BASE VARIANCE ANALYSIS

The following Table 3 sets out HCHI's rate base and working capital calculations for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year, and the following variances:

- 2006 Actual against 2006 Board Approved;
- 2007 Actual against 2006 Actual;
- 2008 Actual against 2008 Actual
- 2009 Bridge Year against 2008 Actual; and
- 2010 Test Year against 2009 Bridge Year.

Table 3
Rate Base Variances

Description	2006 OEB Approved*	2006 Actual Year	Variance from 2006 OEB Approved	2007 Actual Year	Variance from 2006 Actual	2008 Actual Year	Variance from 2007 Actual Year	2009 Bridge Year	Variance from 2008 Actual Year	2010 Test Year	Variance from 2009 Bridge Year
Gross Fixed Assets	37,474,735	42,892,325	5,417,590	45,728,619	2,836,293	50,423,422	4,694,803	54,852,521	4,429,099	58,164,822	3,312,301
Accumulated Depreciation	7,639,543	13,088,866	5,449,323	15,302,560	2,213,695	17,589,099	2,286,538	20,403,075	2,813,976	23,335,161	2,932,087
Net Book Value	29,835,192	29,803,460	(31,732)	30,426,058	622,598	32,834,323	2,408,265	34,449,446	1,615,123	34,829,661	380,214
Average Net Book Value	29,402,632	29,386,766	(15,866)	30,114,759	727,994	31,630,191	1,515,431	33,641,885	2,011,694	34,639,553	997,669
Working Capital	32,014,592	34,269,497	2,254,905	35,678,413	1,408,916	34,344,561	(1,333,852)	35,781,987	1,437,426	36,383,347	601,360
Working Capital Allowance	4,802,189	5,140,425	338,236	5,351,762	211,337	5,151,684	(200,078)	5,367,298	215,614	5,457,502	90,204
Rate Base	34,637,381	34,527,190	(110,191)	35,466,521	939,331	36,781,875	1,315,354	39,009,183	2,227,308	40,097,055	1,087,873

HCHI notes that the 2006 OEB Approved rate base was determined through the 2006 EDR process and is based on the 2004 year end rate base adjusted for Tier 1 Adjustments. Accordingly, the variance between 2006 Actual and 2006 OEB Approved spans a two-year period.

The update to Chapter 2 of the OEB's Filing Requirements dated May 27, 2009 suggest a default materiality threshold for rate base, capital expenditures, OM&A and other

items above a materiality threshold should be used based on a distributor's revenue requirement. HCHI's distribution revenue requirement falls into the category of greater than $10 million and less than or equal to $200 million; resulting in HCHI's materiality threshold calculated as 0.5% of the distribution revenue requirement. The calculation for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge, and 2010 Test are summarized in Table 4 below:

Table 4
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Distribution Revenue Requirement	$11,714,407	$10,616,006	$11,750,648	$11,546,990	$11,299,009	$12,919,004
Variance Calculation - 0.5% of above	$58,572	$53,080	$58,753	$57,735	$56,495	$64,595

HCHI has adopted a variance analysis threshold of $53,080 being the lowest of the variances amongst the years under review. HCHI offers the following comments in respect of the relevant rate base variances identified above in Table 3:

2010 Test Year:

As shown in Table 1 above, the total rate base in the 2010 test year is forecast to be $40,097,055. Average net fixed assets accounts for $34,639,553 of this total. The allowance for working capital totals $5,457,502.

- **2010 Test Year vs. 2009 Bridge Year:**

The total rate base is expected to be $1,087,873 higher in the 2010 Test Year than in the 2009 Bridge Year. This increase is shown in Table 3 above and is attributable primarily to an increase in average net fixed assets of $997,669. The increase in fixed

assets along with the required detailed information for projects is discussed in detail by capital project in Exhibit 2, Tab 2, Schedule 3.

The working capital allowance increased by $90,204 from the 2009 Bridge Year. A detailed calculation of the working capital allowance for the 2010 Test Year can be found at Exhibit 2, Tab 4, Schedule 1.

- **2009 Bridge Year vs. 2008 Actual:**

The total rate base for the 2009 Bridge Year is expected to be $39,009,183, which represents an increase of $2,227,308 over the 2008 Actual year. This change results primarily from an increase in average net assets of $2,011,694. The increase in fixed assets along with the required detailed information for projects is discussed in detail by capital project in Exhibit 2, Tab 2, Schedule 3.

The working capital allowance increased by $215,614 over the 2008 Actual year. This increase is primarily due to the increase in cost of power. A detailed calculation of the working capital allowance for the 2009 Bridge Year can be found at Exhibit 2, Tab 4, Schedule 1.

- **2008 Actual vs. 2007 Actual:**

The rate base of $36,781,875 for 2008 Actual increased over 2007 Actual by $1,315,354. This increase is made up of a change in average net assets of $1,515,431 as a result of capital expenditures and a working capital allowance decrease of $(200,078) primarily due to a large decrease in the Maintenance group of expenses as detailed in Exhibit 4, Tab 2, Schedule 3.

- **2007 Actual vs. 2006 Actual:**

The rate base of $35,466,521 for 2007 Actual increased over 2006 Actual by $939,331. This increase is made up of a change in average net assets of $727,994 as a result of capital expenditures. The working capital allowance increased by $211,337 primarily

due to the large increase in the Maintenance group of expenses as detailed in Exhibit 4, Tab 2, Schedule 3.

- **2006 Actual vs. 2006 Board Approved:**

The rate base of $34,527,190 for 2006 Actual was lower than the 2006 Board Approved by $(110,191). This decrease is made up of a change in average net assets of $(15,866) and a working capital allowance increase of $338,236. The decrease in average net assets is a result of the timing of the capital expenditures from the 2006 Board Approved for the two Tier 1 Rate Base adjustments. The majority of the costs for these two Tier 1 rate base adjustments were posted to capital late 2006 and into 2007 (CDM qualifying investment 3rd tranche and wholesale meter upgrades). Also, there were significant disposals in capital (land, computer equipment, trucks) in the 2005 & 2006 actual years that would account for a portion of this decrease between 2006 Actual and 2006 Board Approved (2004 Actual). The increase in working capital is represented by an increase in costs over a two year period from the 2004 actual amounts (the costs the 2006 Board Approved were based on) and the 2006 actual amounts.

CONTINUITY STATEMENTS:

Table 5
Fixed Asset Continuity Schedule
As at December 31, 2006

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land				0				0	0
1806	Land Rights				0				0	0
1808	Buildings and Fixtures				0				0	0
1810	Leasehold Improvements				0				0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV				0				0	0
1820	Distribution Station Equipment - Normally Primar	399,499	0	16,432	383,067	172,330	17,148	8,929	180,549	202,519
1825	Storage Battery Equipment				0				0	0
1830	Poles, Towers and Fixtures	13,171,893	726,241		13,898,134	3,810,053	672,568		4,482,621	9,415,513
1835	Overhead Conductors and Devices	5,416,435	550,979		5,967,414	1,353,313	286,029		1,639,342	4,328,072
1840	Underground Conduit	218,836	30,145		248,980	29,921	9,586		39,507	209,474
1845	Underground Conductors and Devices	5,940,457	181,310		6,121,767	1,533,836	279,588		1,813,424	4,308,343
1850	Line Transformers	7,771,585	680,654		8,452,239	1,851,931	350,860		2,202,791	6,249,448
1855	Services	1,599,492	215,315		1,814,808	216,054	68,501		284,554	1,530,253
1860	Meters	2,293,245	296,224		2,589,470	543,256	97,070		640,325	1,949,145
1865	Other Installations on Customer's Premises				0				0	0
1905	Land	160,824	0		160,824				0	160,824
1906	Land Rights	695,389	0		695,389	114,734	20,721		135,455	559,934
1908	Buildings and Fixtures	1,241,844	211,430		1,453,274	148,319	33,342		181,661	1,271,613
1910	Leasehold Improvements				0				0	0
1915	Office Furniture and Equipment	222,132	10,612		232,744	93,440	21,980		115,420	117,323
1920	Computer Equipment - Hardware	381,857	75,833	7,725	449,965	218,478	73,386	6,626	285,238	164,727
1925	Computer Software	657,905	172,926		830,831	307,029	126,524		433,553	397,278
1930	Transportation Equipment	1,029,638	161,985	47,527	1,144,096	592,847	115,869	38,358	670,358	473,738
1935	Stores Equipment				0				0	0
1940	Tools, Shop and Garage Equipment	311,051	34,177	809	344,419	138,854	31,482	222	170,114	174,306
1945	Measurement and Testing Equipment				0				0	0
1950	Power Operated Equipment				0				0	0
1955	Communication Equipment	66,281	0		66,281	48,077	7,783		55,860	10,421
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				0				0	0
1985	Sentinel Lighting Rentals				0				0	0
1990	Other Tangible Property				0				0	0
1995	Contributions and Grants	(1,607,552)	(353,824)		(1,961,377)	(171,732)	(70,175)		(241,907)	(1,719,470)
					0				0	0
					0				0	0
	Total before Work in Process	**39,970,812**	**2,994,007**	**72,493**	**42,892,325**	**11,000,740**	**2,142,262**	**54,136**	**13,088,866**	**29,803,460**
	Work in Process				0	0	0	0	0	0
	Total after Work in Process	**39,970,812**	**2,994,007**	**72,493**	**42,892,325**	**11,000,740**	**2,142,262**	**54,136**	**13,088,866**	**29,803,460**

Table 6
Fixed Asset Continuity Schedule
As at December 31, 2007

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	0			0	0			0	0
1806	Land Rights	0			0	0			0	0
1808	Buildings and Fixtures	0			0	0			0	0
1810	Leasehold Improvements	0			0	0			0	0
1815	Transformer Station Equipment - Normally Prim	0			0	0			0	0
1820	Distribution Station Equipment - Normally Prima	383,067	0		383,067	180,549	16,803		197,352	185,716
1825	Storage Battery Equipment	0			0	0			0	0
1830	Poles, Towers and Fixtures	13,898,134	664,216		14,562,350	4,482,621	698,817		5,181,439	9,380,911
1835	Overhead Conductors and Devices	5,967,414	522,891		6,490,305	1,639,342	302,246		1,941,588	4,548,717
1840	Underground Conduit	248,980	16,190		265,170	39,507	10,184		49,690	215,480
1845	Underground Conductors and Devices	6,121,767	348,757		6,470,524	1,813,424	287,581		2,101,006	4,369,518
1850	Line Transformers	8,452,239	480,031		8,932,270	2,202,791	369,674		2,572,465	6,359,805
1855	Services	1,814,808	199,879		2,014,686	284,554	76,851		361,405	1,653,281
1860	Meters	2,589,470	71,178		2,660,648	640,325	105,028		745,353	1,915,295
1865	Other Installations on Customer's Premises	0			0	0			0	0
1905	Land	160,824	0		160,824	0			0	160,824
1906	Land Rights	695,389	0		695,389	135,455	20,721		156,175	539,214
1908	Buildings and Fixtures	1,453,274	456,857		1,910,131	181,661	41,403		223,064	1,687,067
1910	Leasehold Improvements	0			0	0			0	0
1915	Office Furniture and Equipment	232,744	79,660	6,394	306,010	115,420	28,679	4,775	139,324	166,685
1920	Computer Equipment - Hardware	449,965	81,276	50,837	480,404	285,238	77,228	50,735	311,732	168,672
1925	Computer Software	830,831	335,441		1,166,272	433,553	169,901		603,454	562,818
1930	Transportation Equipment	1,144,096	62,197	14,961	1,191,332	670,358	120,219	13,382	777,195	414,137
1935	Stores Equipment	0			0	0			0	0
1940	Tools, Shop and Garage Equipment	344,419	62,743		407,162	170,114	35,957		206,071	201,091
1945	Measurement and Testing Equipment	0			0	0			0	0
1950	Power Operated Equipment	0			0	0			0	0
1955	Communication Equipment	66,281			66,281	55,860	5,477		61,337	4,944
1960	Miscellaneous Equipment	0			0	0			0	0
1970	Load Management Controls - Customer Premis	0			0	0			0	0
1975	Load Management Controls - Utility Premises	0			0	0			0	0
1980	System Supervisory Equipment	0			0	0			0	0
1985	Sentinel Lighting Rentals	0			0	0			0	0
1990	Other Tangible Property	0			0	0			0	0
1995	Contributions and Grants	(1,961,377)	(472,830)		(2,434,207)	(241,907)	(84,182)		(326,089)	(2,108,118)
0	-	0			0	0			0	0
0	-	0			0	0			0	0
	Total before Work in Process	**42,892,325**	**2,908,486**	**72,192**	**45,728,619**	**13,088,866**	**2,282,586**	**68,891**	**15,302,560**	**30,426,058**
0	Work in Process	0			0	0	0	0	0	0
	Total after Work in Process	**42,892,325**	**2,908,486**	**72,192**	**45,728,619**	**13,088,866**	**2,282,586**	**68,891**	**15,302,560**	**30,426,058**

Table 7
Fixed Asset Continuity Schedule
As at December 31, 2008

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	0			0	0			0	0
1806	Land Rights	0			0	0			0	0
1808	Buildings and Fixtures	0			0	0			0	0
1810	Leasehold Improvements	0			0	0			0	0
1815	Transformer Station Equipment - Normally Prim	0			0	0			0	0
1820	Distribution Station Equipment - Normally Prima	383,067	201,933	4,098	580,903	197,352	18,671	4,098	211,925	368,978
1825	Storage Battery Equipment	0			0	0			0	0
1830	Poles, Towers and Fixtures	14,562,350	1,410,907		15,973,257	5,181,439	742,673		5,924,112	10,049,145
1835	Overhead Conductors and Devices	6,490,305	1,243,981		7,734,286	1,941,588	343,998		2,285,586	5,448,700
1840	Underground Conduit	265,170	108,415		373,586	49,690	13,782		63,472	310,113
1845	Underground Conductors and Devices	6,470,524	96,986		6,567,509	2,101,006	300,994		2,401,999	4,165,510
1850	Line Transformers	8,932,270	999,275	121,587	9,809,958	2,572,465	396,029	46,828	2,921,665	6,888,293
1855	Services	2,014,686	137,005		2,151,692	361,405	83,887		445,293	1,706,399
1860	Meters	2,660,648	101,726	17,626	2,744,748	745,353	108,368	3,523	850,198	1,894,550
1865	Other Installations on Customer's Premises	0			0	0			0	0
1905	Land	160,824	0	21,753	139,071	0			0	139,071
1906	Land Rights	695,389	0		695,389	156,175	20,777		176,952	518,437
1908	Buildings and Fixtures	1,910,131	83,776		1,993,907	223,064	46,992		270,056	1,723,851
1910	Leasehold Improvements	0			0	0			0	0
1915	Office Furniture and Equipment	306,010	80,236	39,997	346,248	139,324	33,589	30,302	142,611	203,636
1920	Computer Equipment - Hardware	480,404	40,865	18,166	503,104	311,732	68,273	18,166	361,839	141,265
1925	Computer Software	1,166,272	606,533		1,772,804	603,454	201,666		805,120	967,684
1930	Transportation Equipment	1,191,332	47,890	53,795	1,185,427	777,195	116,678	52,845	841,028	344,399
1935	Stores Equipment	0			0	0			0	0
1940	Tools, Shop and Garage Equipment	407,162	54,509		461,671	206,071	43,164		249,235	212,435
1945	Measurement and Testing Equipment	0			0	0			0	0
1950	Power Operated Equipment	0			0	0			0	0
1955	Communication Equipment	66,281	0		66,281	61,337	3,865		65,202	1,080
1960	Miscellaneous Equipment	0			0	0			0	0
1970	Load Management Controls - Customer Premis	0			0	0			0	0
1975	Load Management Controls - Utility Premises	0			0	0			0	0
1980	System Supervisory Equipment	0			0	0			0	0
1985	Sentinel Lighting Rentals	0			0	0			0	0
1990	Other Tangible Property	0			0	0			0	0
1995	Contributions and Grants	(2,434,207)	(242,212)		(2,676,419)	(326,089)	(101,107)		(427,196)	(2,249,223)
0	-	0			0	0			0	0
0	-	0			0	0			0	0
	Total before Work in Process	**45,728,619**	**4,971,824**	**277,021**	**50,423,422**	**15,302,560**	**2,442,300**	**155,762**	**17,589,099**	**32,834,323**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**45,728,619**	**4,971,824**	**277,021**	**50,423,422**	**15,302,560**	**2,442,300**	**155,762**	**17,589,099**	**32,834,323**

Table 8
Fixed Asset Continuity Schedule
As at December 31, 2009

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	0			0	0			0	0
1806	Land Rights	0			0	0			0	0
1808	Buildings and Fixtures	0			0	0			0	0
1810	Leasehold Improvements	0			0	0			0	0
1815	Transformer Station Equipment - Normally Prima	0			0	0			0	0
1820	Distribution Station Equipment - Normally Primary	580,903	0		580,903	211,925	20,993		232,918	347,985
1825	Storage Battery Equipment	0			0	0			0	0
1830	Poles, Towers and Fixtures	15,973,257	804,807		16,778,063	5,924,112	793,026		6,717,138	10,060,926
1835	Overhead Conductors and Devices	7,734,286	1,334,259		9,068,545	2,285,586	415,753		2,701,339	6,367,206
1840	Underground Conduit	373,586	234,685		608,270	63,472	23,935		87,407	520,863
1845	Underground Conductors and Devices	6,567,509	136,976		6,704,485	2,401,999	306,695		2,708,694	3,995,791
1850	Line Transformers	9,809,958	632,358		10,442,316	2,921,665	430,066		3,351,731	7,090,585
1855	Services	2,151,692	182,013		2,333,705	445,293	93,289		538,582	1,795,123
1860	Meters	2,744,748	29,199		2,773,947	850,198	110,780		960,978	1,812,969
1865	Other Installations on Customer's Premises	0			0	0			0	0
1870	Leased Property on Customer Premises	0			0	0			0	0
1875	Street Lighting and Signal Systems	0			0	0			0	0
1905	Land	139,071			139,071	0			0	139,071
1906	Land Rights	695,389	0		695,389	176,952	17,775		194,727	500,662
1908	Buildings and Fixtures	1,993,907	19,435		2,013,342	270,056	48,015		318,071	1,695,271
1910	Leasehold Improvements	0			0	0			0	0
1915	Office Furniture and Equipment	346,248	0		346,248	142,611	32,842		175,453	170,794
1920	Computer Equipment - Hardware	503,104	42,542		545,646	361,839	65,982		427,821	117,825
1925	Computer Software	1,772,804	420,105		2,192,909	805,120	349,886		1,155,006	1,037,903
1930	Transportation Equipment	1,185,427	586,656		1,772,083	841,028	181,845		1,022,873	749,210
1935	Stores Equipment	0			0	0			0	0
1940	Tools, Shop and Garage Equipment	461,671	53,864		515,535	249,235	28,900		278,135	237,399
1945	Measurement and Testing Equipment	0			0	0			0	0
1950	Power Operated Equipment	0			0	0			0	0
1955	Communication Equipment	66,281			66,281	65,202	1,080		66,282	(0)
1960	Miscellaneous Equipment	0			0	0			0	0
1970	Load Management Controls - Customer Premises	0			0	0			0	0
1975	Load Management Controls - Utility Premises	0			0	0			0	0
1980	System Supervisory Equipment	0			0	0			0	0
1985	Sentinel Lighting Rentals	0			0	0			0	0
1990	Other Tangible Property	0			0	0			0	0
1995	Contributions and Grants	(2,676,419)	(47,800)		(2,724,219)	(427,196)	(106,886)		(534,082)	(2,190,137)
	Total before Work in Process	**50,423,422**	**4,429,099**	**0**	**54,852,521**	**17,589,099**	**2,813,976**	**0**	**20,403,075**	**34,449,446**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**50,423,422**	**4,429,099**	**0**	**54,852,521**	**17,589,099**	**2,813,976**	**0**	**20,403,075**	**34,449,446**

Table 9
Fixed Asset Continuity Schedule
As at December 31, 2010

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	0			0	0			0	0
1806	Land Rights	0			0	0			0	0
1808	Buildings and Fixtures	0			0	0			0	0
1810	Leasehold Improvements	0			0	0			0	0
1815	Transformer Station Equipment - Normally Prima	0			0	0			0	0
1820	Distribution Station Equipment - Normally Primary	580,903	0		580,903	232,918	20,994		253,911	326,992
1825	Storage Battery Equipment	0			0	0			0	0
1830	Poles, Towers and Fixtures	16,778,063	726,388		17,504,451	6,717,138	822,082		7,539,220	9,965,232
1835	Overhead Conductors and Devices	9,068,545	572,938		9,641,484	2,701,339	438,670		3,140,010	6,501,474
1840	Underground Conduit	608,270	364,927		973,197	87,407	38,532		125,939	847,258
1845	Underground Conductors and Devices	6,704,485	214,503		6,918,989	2,708,694	315,275		3,023,969	3,895,019
1850	Line Transformers	10,442,316	515,365		10,957,681	3,351,731	450,681		3,802,412	7,155,269
1855	Services	2,333,705	196,004		2,529,709	538,582	101,129		639,711	1,889,997
1860	Meters	2,773,947	87,763		2,861,710	960,978	114,290		1,075,269	1,786,442
1865	Other Installations on Customer's Premises	0			0	0			0	0
1870	Leased Property on Customer Premises	0			0	0			0	0
1875	Street Lighting and Signal Systems	0			0	0			0	0
1905	Land	139,071			139,071	0			0	139,071
1906	Land Rights	695,389	0		695,389	194,727	17,775		212,502	482,887
1908	Buildings and Fixtures	2,013,342	0		2,013,342	318,071	48,015		366,086	1,647,256
1910	Leasehold Improvements	0			0	0			0	0
1915	Office Furniture and Equipment	346,248	5,336		351,584	175,453	30,760		206,213	145,371
1920	Computer Equipment - Hardware	545,646	18,676		564,322	427,821	50,799		478,620	85,702
1925	Computer Software	2,192,909	429,068		2,621,977	1,155,006	388,778		1,543,784	1,078,193
1930	Transportation Equipment	1,772,083	273,600		2,045,683	1,022,873	177,370		1,200,243	845,439
1935	Stores Equipment	0			0	0			0	0
1940	Tools, Shop and Garage Equipment	515,535	39,333		554,868	278,135	29,086		307,222	247,646
1945	Measurement and Testing Equipment	0			0	0			0	0
1950	Power Operated Equipment	0			0	0			0	0
1955	Communication Equipment	66,281			66,281	66,282	0		66,282	(0)
1960	Miscellaneous Equipment	0			0	0			0	0
1970	Load Management Controls - Customer Premises	0			0	0			0	0
1975	Load Management Controls - Utility Premises	0			0	0			0	0
1980	System Supervisory Equipment	0			0	0			0	0
1985	Sentinel Lighting Rentals	0			0	0			0	0
1990	Other Tangible Property	0			0	0			0	0
1995	Contributions and Grants	(2,724,219)	(131,600)		(2,855,819)	(534,082)	(112,150)		(646,232)	(2,209,587)
	Total before Work in Process	**54,852,521**	**3,312,301**	**0**	**58,164,822**	**20,403,075**	**2,932,087**	**0**	**23,335,161**	**34,829,661**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**54,852,521**	**3,312,301**	**0**	**58,164,822**	**20,403,075**	**2,932,087**	**0**	**23,335,161**	**34,829,661**

Table 10
Gross Assets

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Bridge ($)	Variance from 2008 Actual	2010 Test ($)	Variance from 2009 Bridge
Land and Buildings											
1805-Land											
1806-Land Rights											
1808-Buildings and Fixtures											
1905-Land	260,907	160,824	(100,083)	160,824	-	139,071	(21,753)	139,071	-	139,071	
1906-Land Rights	695,389	695,389	0	695,389	-	695,389	-	695,389	-	695,389	
1810-Leasehold Improvements									-		
Sub-Total-Land and Buildings	956,296	856,214	(100,083)	856,214	-	834,461	(21,753)	834,461	-	834,461	-
TS Primary Above 50											
1815-Transformer Station Equipment - Normally Primary above 50 kV											
Sub-Total-TS Primary Above 50											
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	406,395	383,067	(23,328)	383,067	-	580,903	197,835	580,903	-	580,903	
Sub-Total-DS	406,395	383,067	(23,328)	383,067	-	580,903	197,835	580,903	-	580,903	-
Poles and Wires											
1830-Poles, Towers and Fixtures	12,806,911	13,898,134	1,091,223	14,562,350	664,216	15,973,257	1,410,907	16,778,063	804,807	17,504,451	726,388
1835-Overhead Conductors and Devices	4,824,797	5,967,414	1,142,617	6,490,305	522,891	7,734,286	1,243,981	9,068,545	1,334,259	9,641,484	572,938
1840-Underground Conduit	199,789	248,980	49,191	265,170	16,190	373,586	108,415	608,270	234,685	973,197	364,927
1845-Underground Conductors and Devices	5,496,724	6,121,767	625,043	6,470,524	348,757	6,567,509	96,986	6,704,485	136,976	6,918,989	214,503
Sub-Total-Poles and Wires	23,328,221	26,236,295	2,908,074	27,788,349	1,552,054	30,648,638	2,860,289	33,159,365	2,510,727	35,038,121	1,878,756
Line Transformers											
1850-Line Transformers	7,142,237	8,452,239	1,310,002	8,932,270	480,031	9,809,958	877,688	10,442,316	632,358	10,957,681	515,365
Sub-Total-Line Transformers	7,142,237	8,452,239	1,310,002	8,932,270	480,031	9,809,958	877,688	10,442,316	632,358	10,957,681	515,365
Services and Meters											
1855-Services	1,215,365	1,814,808	599,443	2,014,686	199,879	2,151,692	137,005	2,333,705	182,013	2,529,709	196,004
1860-Meters	2,132,133	2,589,470	457,337	2,660,648	71,178	2,744,748	84,101	2,773,947	29,199	2,861,710	87,763
Sub-Total-Services and Meters	3,347,498	4,404,278	1,056,780	4,675,334	271,057	4,896,440	221,106	5,107,652	211,212	5,391,419	283,767
General Plant											
1908-Buildings and Fixtures	1,095,753	1,453,274	357,521	1,910,131	456,857	1,993,907	83,776	2,013,342	19,435	2,013,342	
1910-Leasehold Improvements											
Sub-Total-General Plant	1,095,753	1,453,274	357,521	1,910,131	456,857	1,993,907	83,776	2,013,342	19,435	2,013,342	-
IT Assets											
1920-Computer Equipment - Hardware	271,463	449,965	178,502	480,404	30,439	503,104	22,700	545,646	42,542	564,322	18,676
1921-Computer Equipment											
1921-Computer Equipment - Hardware post March 22, 2005											
1925-Computer Software	324,705	830,831	506,126	1,166,272	335,441	1,772,804	606,533	2,192,909	420,105	2,621,977	429,068
Sub-Total-IT Assets	596,168	1,280,795	684,627	1,646,676	365,880	2,275,908	629,232	2,738,555	462,647	3,186,299	447,744
Equipment											
1915-Office Furniture and Equipment	195,376	232,744	37,368	306,010	73,266	346,248	40,238	346,248		351,584	5,336
1930-Transportation Equipment	972,529	1,144,096	171,567	1,191,332	47,236	1,185,427	(5,905)	1,772,083	586,656	2,045,683	273,600
1935-Stores Equipment											
1940-Tools, Shop and Garage Equipment	254,887	344,419	89,532	407,162	62,743	461,671	54,509	515,535	53,864	554,868	39,333
1945-Measurement and Testing Equipment											
1950-Power Operated Equipment											
1955-Communication Equipment	53,920	66,281	12,361	66,281	-	66,281	-	66,281		66,281	
1960-Miscellaneous Equipment											
Sub-Total-Equipment	1,476,712	1,787,540	310,828	1,970,785	183,244	2,059,627	88,842	2,700,147	640,520	3,018,416	318,269
Other Distribution Assets											
1825-Storage Battery Equipment											
1970-Load Management Controls - Customer Premises											
1975-Load Management Controls - Utility Premises											
1980-System Supervisory Equipment											
1985-Sentinel Lighting Rental Units											
1990-Other Tangible Property											
1995-Contributions and Grants - Credit	(874,545)	(1,961,377)	(1,086,832)	(2,434,207)	(472,830)	(2,676,419)	(242,212)	(2,724,219)	(47,800)	(2,855,819)	(131,600)
1996-Hydro One S/S Contribution											
Sub-Total-Other Distribution Assets	(874,545)	(1,961,377)	(1,086,832)	(2,434,207)	(472,830)	(2,676,419)	(242,212)	(2,724,219)	(47,800)	(2,855,819)	(131,600)
GROSS ASSET TOTAL	37,474,735	42,892,325	5,417,589	45,728,619	2,836,293	50,423,422	4,694,803	54,852,521	4,429,099	58,164,822	3,312,301

VARIANCE ANALYSIS ON GROSS ASSETS

The Gross Asset Variance analysis for those variances highlighted in Table 10 of Exhibit 2, Tab 2, Schedule 2 is provided as follows.

2006 Actual vs. 2006 Board Approved

- **Account 1905 – Land**

2006 Actual vs. 2006 Board Approved, $(100,083).

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

- No investments in land in 2004, 2005 or 2006
- Two disposals of land resulting in the negative variance of $(100,083)
    1. 2004 disposal of Nairne St. property, Caledonia – value of land recorded in HCHI's capital asset records - $165
    2. 2005 disposal of George St. property, Dunnville – value of land recorded in HCHI's capital asset records - $100,000

- **Construction Projects - Accounts as follows:**
    - **1830 – Poles, Towers & Fixtures $1,091,223**
    - **1835 – Overhead (O/H) Conductors and Devices $1,142,617**
    - **1840 – Underground (U/G) Conduit $49,191**
    - **1845 – Underground (U/G) Conductors and Devices $625,043**
    - **1850 – Line Transformers $1,310,002**

2006 Actual vs. 2006 Board Approved, $4,218,076.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 normal investments.

The table below represents HCHI's actual investment in construction projects for the years 2004, 2005 and 2006. The total spending for this period will be slightly greater than the variance between the 2006 Board Approved and the 2006 Actual due to the averaging of the 2003 and 2004 actual amounts as recorded in the 2006 Board Approved year. Another contributing factor to this variance is the additional amount spent on the Hagersville Conversion capital project (project #8) than recorded as a Rate Base Tier 1 Adjustment in the 2006 Board Approved in accordance with the 2006 rate model. This project was partially funded through the third tranche funding from HCHI's Conservation and Demand Management program.

Construction projects detailed as follows:

Construction Projects	Poles, Towers & Fixtures (1830)	O/H Conductor & Devices (1835)	U/G Conduit (1840)	U/G Conductors & Devices (1845)	Line Transformers (1850)	Total
2004 Projects:						
Project #1	1,790	26,705		104	15,762	44,361
Project #2	11		3,194	36,839		40,044
Project #3	472		4,827	793	23,782	29,874
Project #4			10,087	12,351		22,437
Project #5	38,766	89,014			28,120	155,900
Project #6		7,593				7,593
Project #7	4,836	2,752	49	270	2,126	10,033
Project #8	4,446	3,565	1,038	242	32,931	42,222
Project #9	6,521	12,987	9,972	66,662	824	96,966
Project #10	13,325	13,286		3,271	22,627	52,509
Project #11		328				328
Project #12	15,198	38,950			2,956	57,104
Project #13	26,395	43,936			20,895	91,226
Project #14	59,342	44,310				103,652
Betterments	40,961	26,363			48,083	115,407

Construction Projects	Poles, Towers & Fixtures (1830)	O/H Conductor & Devices (1835)	U/G Conduit (1840)	U/G Conductors & Devices (1845)	Line Transformers (1850)	Total
Line Extensions	111,852	68,047		8,027	193,978	381,904
2004 Subtotal:	323,915	377,836	29,167	128,558	392,084	1,251,560
2005 Projects:						
Project #1	128,336	101,043				229,379
Project #2		14,506				14,506
Project #3	784	10,137				10,921
Project #4	54,689	143,834	7,507	11,427	116,920	334,377
Project #5		53	686			739
Project #6		4,605			58	4,663
Project #7	47,161	72,963			22,779	142,903
Project #8	242,124	117,597			150,922	510,643
Project #9				372,610	95,400	468,010
Betterments	58,959	43,373	195		28,727	131,254
Line Extensions	102,313	73,003	1,227	1,011	248,358	425,912
2005 Subtotal:	634,366	581,114	9,615	385,048	663,164	2,273,307
2006 Projects:						
Project #1	7,965	21,793			22,466	52,224
Project #2	86,330	54,391			18,540	159,261
Project #3			16,073	7,320	638	24,031
Project #4	1,930	12,085				14,015
Project #5	26,051	19,769		1,121	4,429	51,370
Project #6	71,172	19,580			902	91,654
Project #7				121,102	53,155	174,257
Betterments	130,589	150,845	6,794	11,010	79,516	378,754
Line Extensions	140,986	75,591	2,139	34,711	270,448	523,875
2006 Subtotal:	465,023	354,054	25,006	175,264	450,094	1,469,441
USoA Total	1,423,304	1,313,004	63,788	688,870	1,505,342	
Total Investment 2004 - 2006	4,994,308					

Note: 2006 Subtotal by USoA does not equal 2006 Additions as detailed in Table 6 "Fixed Asset Continuity Schedule as at December 31, 2006" due to allocation of 2006 spending on account of 2005 Capital Projects included in the "2005 Projects" portion of the above table. The Continuity Schedule includes this spending in the year of posting; 2006.

2004 Specific Construction Projects

Project # 1 Convert Dunnville High School to 27.6kV – Dunnville
Type of Project Customer Demand
Amount of Project $44,361
Description of Project

The Dunnville High School was in the process of upgrading their electrical service. The upgrade provided the opportunity to convert the service from 4.16kV primary to 27.6kV primary. This conversion supports HCHI's strategy to eliminate distribution stations. This work involved replacing the primary cables from a termination pole to a pad-mounted transformer and replacing the pad-mounted transformer.

Business Value	Comments
Reliability/Performance	The existing service was being supplied from Forest DS which was reaching the end of life and reliability was less than expected. Converting this larger load to a 27.6kV supply would increase reliability.
Community Relations	No impact.
Safety	Replacement of old infrastructure lessens an age related safety incident.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 2 Complete Loop – Brelus, Brookfield, & Fairview – Dunnville
Type of Project Reliability
Amount of Project $40,044
Description of Project

This project involves the installation of primary pad-mounted junction points and new underground primary cable.

Business Value	Comments
Reliability/Performance	This area had been affected by underground primary cable failures and only had one electrical supply point. As a result of this single supply point, cable failures resulted in significant customer outages while the emergency repair was made.

	Installing a second primary supply point (loop feed) provides security by allowing the faulted section of cable to be isolated from the distribution system through switching procedures. Repair work can be scheduled during normal working hours reducing repair costs.
Community Relations	Reduced duration of an outage has a positive impact on customers.
Safety	Reduces the impact of a lengthy outage which causes some customers to use inappropriate heating and lighting methods which often enough cause fires and air quality issues (for example candles and outdoor heaters).
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 3 Replace Defective Transformer Pads – Various Locations
Type of Project Sustainment
Amount of Project $29,874
Description of Project

This project involves replacing existing fiberglass pad-mounted transformer foundations with concrete foundations. In conjunction with this work if the transformer condition is poor it is also changed. This is a multi-year project.

Business Value	Comments
Reliability/Performance	Fiberglass pad-mounted transformer foundations installed in a number of subdivisions are starting to fail. A defective foundation could lead to the shifting of the transformer and possible breakage of transformer bushings and connections. This has the potential of resulting in an outage. Replacing the foundation eliminates this risk.
Community Relations	A level foundation looks better and lowers the number of complaints from customers.
Safety	The fiberglass foundations deteriorate to a point where they start to cave in. This causes gaps between the transformer and the foundation and off level installations which are unsightly. Gaps which are large enough to allow children to poke sticks or reach inside is a potentially serious electrical hazard. Replacement eliminates the risk.
Regulatory	Eliminates the potential for Electrical Safety Authority

Intervention	intervention.
Environmental Stewardship	No Impact.

Project # 4 Install Switching Cubicle at Willow Glen and Bramble – Townsend
Type of Project Reliability
Amount of Project $22,437
Description of Project

This project involves installing primary cable and two primary pad-mounted junction points.

Business Value	Comments
Reliability/Performance	This area had a single electrical supply point. A single cable failure would result in an extended customer outage while an emergency repair was made. Installing a second primary supply point (loop feed) provides security by allowing the faulted section of cable to be isolated from the distribution system through switching procedures. Repair work can then be scheduled during normal working hours reducing repair costs.
Community Relations	Reduced duration of an outage has a positive impact on customers.
Safety	Reduces the impact of a lengthy outage which causes some customers to use inappropriate heating and lighting methods which often enough cause fires and air quality issues (for example candles and outdoor heaters).
Regulatory Intervention	No impact.
Environmental Stewardship	No Impact.

Project # 5 Elimination of Long-Term Load Transfers at Haldimand Road 74 and Concessions 14, 16, and 17 – Walpole
Type of Project Regulatory
Amount of Project $155,900
Description of Project

This project involves installing poles, transformers and conductors to supply HCHI customers from HCHI distribution system infrastructure.

Historical service territory boundaries were changed during the purchase of HONI assets in the late 1990's and the amalgamation of utilities in the municipality of Haldimand County in 2000. Boundary issues exist with Norfolk Power Distribution Inc. ("NPI") and HONI. As the boundaries were changed the assets in place did not always match the new service provider. The name "long term load transfers" indicates areas when one of two conditions exist:

- The customer is physically located within HCHI's service territory but is fed from assets owned by either NPI or HONI
- The customer is physically located within NPI or HONI's service territory but is fed from assets owned by HCHI.

The elimination of load transfer arrangements is a requirement of the Distribution System Code. The dates by which the elimination of load transfer arrangements is to be completed has changed a number of times as follows:

- Original date October 2008
- Amended date January 31, 2009
- Latest date June 30, 2014

This project generically called "Long Term Load Transfers" is present in a number of different locations within Haldimand County and the reasons for the work are the same regardless of location. This is a multi-year project.

Business Value	Comments
Reliability/Performance	Customers are fed from neighbouring utilities (HONI or NPI) assets. Emergency response and final restoration to these customers is often delayed because both utilities must coordinate restoration efforts. Performance can be enhanced when the territorial energy provider provides the service exclusive of the other utility.
Community Relations	Customers generally don't understand that there may be a difference between who supplies the energy bill and who controls the asset from which they receive the energy. Customer's concern over less than optimum response time is

	eliminated when there is one service provider.
Safety	Reduces the need to coordinate emergency services with neighboring utilities and thus reduces the risk of a safety incident due to communication issues.
Regulatory Intervention	Eliminates potential intervention from Ontario Energy Board by complying with regulation.
Environmental Stewardship	No Impact.

Project # 6 Lightning Arrester Installations, Various Locations
Type of Project Reliability
Amount of Project $7,593
Description of Project

This project involves installing lightning arrester banks in the distribution system where none existed before. This is a multi-year project.

Business Value	Comments
Reliability/Performance	Additional lightning arrester banks will reduce lightning related outages and increase reliability.
Community Relations	Reduces the frequency of outages which has a positive impact on customers.
Safety	Reduces lightning damage to equipment and reduces exposure to potentially hazardous situations for staff.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 7 Pole Relocation at Hwy 6 and Greendale Drive, Caledonia
Type of Project Municipal
Amount of Project $10,033
Description of Project

This project involves installing/removing poles due to a road realignment where the existing poles would be in the new roadway or too close to the travelled portion of the road.

Business Value	Comments
Reliability/Performance	No Impact.
Community Relations	Supports municipal road projects.
Safety	No Impact.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 8 27.6kV Conversion at Hwy 6 and Greendale Drive, Caledonia
Type of Project Municipal
Amount of Project $42,222
Description of Project

This project was performed in conjunction with Project # 7. The existing 8.3kV pole line was already insulated for 27kV so the conversion was accomplished by changing only the transformers and devices to a higher voltage rating. The change of poles for the road alignment provided the opportunity to transfer the supply from 8.3kV to 27.6kV. The 8.3kV supply in this case is from a HONI Distribution Station – Argyle DS. This project supports HCHI's strategy to eliminate supply points from HONI assets and eliminate sub-transmission charges.

Business Value	Comments
Reliability/Performance	Converting to a higher voltage reduces system losses.
Community Relations	Customers generally don't understand that there may be a difference between who supplies the energy bill and who controls the asset from which they receive the energy. Customer's concern over less than optimum response time is eliminated when there is one service provider.
Safety	Reduces the need to coordinate emergency services with HONI and thus reduces the risk of a safety incident due to communication issues.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 9 Selkirk Distribution Station (DS) South – Risers, Poles, and Feeders, Caledonia
Type of Project Sustainment
Amount of Project $96,966
Description of Project

This project involves the installation of poles, devices, and underground cable. This project was initiated to support the rebuilding of Selkirk DS following a catastrophic failure of the substation equipment in March of 2004. The feeder egress cables and poles were upgraded in conjunction with the rebuild of the station switchgear.

Business Value	Comments
Reliability/Performance	The existing equipment was compromised in the station failure and was in poor condition. Installing new equipment to today's design standards will improve reliability.
Community Relations	No Impact.
Safety	Replacement of old infrastructure lessens an age related safety incident.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 10 Caledonia Fairgrounds – Eliminate Primary, Caledonia
Type of Project Hazard
Amount of Project $52,509
Description of Project

This project involves the installation of distribution transformers on the road allowance to eliminate the need for overhead primary conductor on fairgrounds property.

Business Value	Comments
Reliability/Performance	Removal of distribution equipment at end of life will increase reliability.
Community Relations	Supports municipal projects.
Safety	The existing pole line was placed in an area in which there was much activity. When events were staged at the fairgrounds, the risk of an electrical contact incident taking place was high. This project eliminates these hazards and risks.

Regulatory Intervention	Eliminates the potential for Electrical Safety Authority intervention.
Environmental Stewardship	No Impact.

Project # 11 Primary Fault Indicators, Various Locations
Type of Project Reliability
Amount of Project $328
Description of Project

This project involves the installation of faulted circuit indicators on the distribution system. This is a multi-year project.

Business Value	Comments
Reliability/Performance	When a fault flows through these devices they emit a flashing strobe beacon. This enables emergency response crews to pinpoint fault direction faster thus increasing restoration performance.
Community Relations	No Impact.
Safety	Many of HCHI's pole lines are off road and are not accessible by truck. In emergency situations these lines are patrolled by foot and depending on the conditions (ice, snow, night, rain, etc,) can pose a risk of injury to staff. The devices may eliminate the need to patrol these off road lines thus, eliminating the risk of injury.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 12 Load Break Disconnect Switch Replacement, Various Locations
Type of Project Sustainment
Amount of Project $57,104
Description of Project

This project involves the replacement of both air break and load break disconnect switches. This is a multi-year project.

Business Value	Comments

Reliability/Performance	Existing switches have reached or are approaching the end of life. Replacement will increase reliability by allowing more flexibility in switching and eliminating switches in poor condition.
Community Relations	No Impact.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

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Project # 13 Feeder Canal Road – Remove Line from Swamp, Dunnville
Type of Project Sustainment
Amount of Project $91,226
Description of Project

This project involves the relocation of an off road pole line located in a swamp to the road allowance.

Business Value	Comments
Reliability/Performance	The existing pole line is at end of life and it is inaccessible due to its location in a swamp area. Replacement and relocation will increase reliability due to better quality equipment and better access.
Community Relations	No Impact.
Safety	Once relocated staff will be able to maintain the equipment using normal rolling equipment as opposed to climbing poles with spurs. This reduces the risk of an incident.
Regulatory Intervention	No Impact.
Environmental Stewardship	Removes transformers from swampy area and reduces the impact of an oil spill into a waterway.

Project # 14 River Crossings – Yaremy (South Side of River), North Cayuga and Nairne (North Side of River), Caledonia (Two Structures)
Type of Project Sustainment
Amount of Project $103,652
Description of Project

This project involves the replacement of river crossing pole structures. The Grand River divides HCHI's service territory and the distribution system must cross the river in limited locations to serve customers. These locations are therefore, critical to the distribution system. This is a multi-year project with structures located at different locations.

. Business Value	Comments
Reliability/Performance	The existing pole structures are at end of life. Replacement will increase reliability.
Community Relations	No Impact.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident.
Regulatory Intervention	A failure of one of these structures could have a regulator impact due to regulations surrounding projects over waterways. Replacing the structures reduces the risk of impacting the waterway by reducing the risk of a failure where conductors could land in the water.
Environmental Stewardship	Waterways are generally classified as sensitive project areas. Rebuilding existing assets reduces the risk of a negative impact.

2005 Specific Construction Projects

Project # 1 River Crossings – Stoney Creek Road, York (South Side of River) – McClung Road (West Side of River), Caledonia & Forfar (South Side of River), Caledonia (Three Structures) Caledonia
Type of Project Sustainment
Amount of Project $229,379
Description of Project

See comments under Project # 14 in 2004

Project # 2 Primary Fault Indicators, Various Locations
Type of Project Reliability
Amount of Project $14,506
Description of Project

See comments under Project # 11 in 2004

Project # 3 Load Break Disconnect Switch Replacement, Various Locations
Type of Project Sustainment
Amount of Project $10,921
Description of Project

See comments under Project # 12 in 2004

Project # 4 Eliminate Forest Street 4.16kV Distribution Station (DS) – Dunnville
Type of Project Sustainment
Amount of Project $334,377
Description of Project

This DS located in the community centre of Dunnville was installed in approximately 1967-68 and consisted of a station transformer and enclosed metal-clad switchgear. The age of the equipment was unknown because the nameplates were deteriorated. The best guess on age is that it was new when the station was built (it may however, been used equipment). This project involves installing a number of step down transformer banks to replace the transformation at the DS.

Business Value	Comments
Reliability/Performance	Station approaching its design life of 40 years. Station had reliability issues related to inadequate maintenance practices over the years and age of equipment. A service provider was utilized to respond to faulted equipment and this always increased the length of an outage due to increased response time of the service provider.
Community Relations	Station was located in former commercial/industrial area being converted to residential area. Removal of the station facilitates residential development of the property.
Safety	The nature of the design with metal-clad switchgear housed in a steel building posed a safety hazard to personnel. HCHI has no station maintenance trade staff and existing line trade staff have limited knowledge of this type of installation. This

	knowledge gap increases the risk of an incident during fault conditions at the station.
Regulatory Intervention	No Impact
Environmental Stewardship	The station transformer was close to storm sewers and it had no oil containment provisions. Risk of a spill to the storm sewer was medium to high.

Project # 5 Replace Defective Transformer Pads – Various Locations
Type of Project Sustainment
Amount of Project $739
Description of Project

See comments under Project # 3 in 2004

Project # 6 Lightning Arrester Installations, Various Locations
Type of Project Reliability
Amount of Project $4,663
Description of Project

See comments under Project # 6 in 2004

Project # 7 Re-Insulate Decewsville Road & Replace Defective Poles, North Cayuga
Type of Project Sustainment
Amount of Project $142,903
Description of Project

This project involves changing the primary insulators and replacement of poles.

Business Value	Comments
Reliability/Performance	The existing insulators have had a number of failures in the past and a number of poles have reached the end of life. Replacement will increase reliability.
Community Relations	No Impact.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident.
Regulatory Intervention	No Impact.
Environmental	No Impact.

Stewardship	

Project # 8 Hagersville Voltage Conversion – Phase 1 and 2, Hagersville
Type of Project Sustainment
Amount of Project $510,643
Description of Project

John DS located in the community centre of Hagersville was installed in approximately 1949 and consisted of a station transformer and open steel structure. This equipment has exceeded its design life. This project involves changing distribution equipment to support a higher 27.6kV primary voltage and eliminate the need for the DS.

This capital project was partially funded through the third tranche funding from HCHI's Conservation and Demand Management program.

Business Value	Comments
Reliability/Performance	Station exceeding its design life of 40 years. Replacing the station with new distribution equipment will increase reliability. Converting to a higher voltage supports reduced losses.
Community Relations	Station was located in commercial/residential area. Eliminating the station will be viewed positively by customers.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident.
Regulatory Intervention	No Impact
Environmental Stewardship	The station was close to storm sewers and it had no oil containment provisions. Risk of a spill to the storm sewer was medium to high.

Project # 9 Subdivisions – Assumption of Assets (5 subdivisions)
Amount of Project $468,010

Per the OEB's Distribution System Code (DSC), effective with new subdivision agreements signed after November 2000, a distributor is required to rebate the developer of a subdivision for their eligible portion of the costs by completing an economic evaluation model. This model weighs the future revenue to be collected by

the distributor against the capital & maintenance costs associated with the subdivision. The shortfall between the revenue and costs is the amount to be contributed to the subdivision by the developer. This capital project represents the assets assumed two years after the year serviced for 5 subdivisions within Haldimand County less the offsetting rebate to each developer, the amount of which is shown in contributed capital.

2006 Specific Construction Projects

Project # 1 Step Down Transformer to Convert Concession 8 & 9, Walpole
Type of Project Reliability
Amount of Project $52,224
Description of Project

This project involves installing a step down transformer bank and changing the primary supply from 8.3kV to 27.6kV.

Business Value	Comments
Reliability/Performance	The voltage control in this area is poor resulting in low voltage to customers under peak loading conditions. Changing the primary voltage source and direction will correct voltage problems and increase performance.
Community Relations	Customers will see a positive impact with better voltage regulation.
Safety	Low voltage problems can contribute to customer equipment failure and stress on the customers electrical system. This has the potential to cause fire hazards. Better voltage regulation and the elimination of low voltage reduces the risk of failure.
Regulatory Intervention	Eliminates the potential for Electrical Safety Authority intervention.
Environmental Stewardship	No Impact.

Project # 2 Elimination of Long-Term Load Transfers Haldibrook Road & Hwy 6, Caledonia, McClung & Haldibrook, Caledonia, Concession 12 and Haldimand Road 74, Walpole
Type of Project Regulatory
Amount of Project $159,261
Description of Project

See comments under Project # 5 in 2004

Project # 3 Replace Defective Transformer Pads – Various Locations
Type of Project Sustainment
Amount of Project $24,031
Description of Project

See comments under Project # 3 in 2004

Project # 4 Load Break Disconnect Switch Replacement, Various
Type of Project Sustainment
Amount of Project $14,015
Description of Project

See comments under Project # 12 in 2004

Project # 5 Elimination of Long-Term Load Transfers Poth Road, Dunnville
Type of Project Regulatory
Amount of Project $51,370
Description of Project

See comments under Project # 5 in 2004

Project # 6 Hawk Road Rebuild – Stelco Industrial Park, Phase I, Nanticoke
Type of Project Sustainment
Amount of Project $91,654
Description of Project

This project involves installing a new three phase pole line complete with concrete poles, transformers, and conductors. The existing supply is underground primary cable in a duct and vault system. This installation is critical due to a number of large customers.

Business Value	Comments
Reliability/Performance	The original system of underground primary cable has been prone to failure and the original installation is not to today's standards. Rebuilding will increase reliability and performance.
Community Relations	Customers will see a positive impact with better reliability.

Safety	The standards to which the underground primary was installed were less than adequate and created risks for staff who contended with less than ideal conditions. Changing to an overhead system reduces the risk to staff.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 7 Subdivisions – Assumption of Assets (2 subdivisions)
Amount of Project $174,257

This capital project represents the assets assumed two years after the year serviced for 2 subdivisions within Haldimand County less the offsetting rebate to each developer, the amount of which is shown as contributed capital.

2004, 2005, and 2006 Other Projects

Betterments

Generally involves replacing a non consumable item like an overhead conductor of greater capacity or an insulator with greater kV rating. This activity does not increase the distribution system footprint.

Line Extensions

A line extension is required when a new connection is added but there is no electrical distribution infrastructure in the area. To service the new customer it is necessary to extend the distribution system to the proposed location. This activity increases the distribution system footprint. An economic evaluation (refer to 2005 project #9) is conducted in order to calculate the required capital contribution from the customer and is recorded in contributed capital.

- **Account 1855 – Services**

2006 Actual vs. 2006 Board Approved, $599,443.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

The table below represents HCHI's actual capital spending for new and upgraded services that account for the assets from the distribution system location to the demarcation point or first point of attachment of the customer using overhead (O/H) conductor and underground (U/G) conductor for the years 2004, 2005 and 2006. The rules governing this connection process are described in HCHI's Conditions of Service. The total spending for this period will be slightly greater than the variance between the 2006 Board Approved and the 2006 Actual due to the averaging of the 2003 and 2004 actual amounts as recorded in the 2006 Board Approved year. Any offsetting capital contribution collected from the customer is recorded in the appropriate contributed capital account.

Services, new and upgraded, detailed as follows:

Service	2004	2005	2006	Total
Upgrade – O/H <= 200 Amp, Single Phase	67,106	80,225	63,959	211,290
Upgrade – O/H > 200 Amp, Single Phase	4,048	11,668	23,833	39,549
Upgrade – O/H <= 200 Amp, Three Phase	3,112	1,637		4,749
Upgrade – O/H > 200 Amp, Three Phase	1,107	2,606		3,713
Upgrade – U/G <= 200 Amp, Single Phase	170,024	143,483	110,406	423,913
Upgrade – U/G > 200 Amp, Single Phase	1,782	1,296	296	3,374
Upgrade – U/G	511		477	988

<= 200 Amp, Three Phase				
Upgrade – U/G > 200 Amp, Three Phase	1,705	3,360	4,785	9,850
New - Miscellaneous	10,243	10,035	11,559	31,837
Total Services	259,638	254,310	215,315	729,263

- **Account 1860 – Meters**

2006 Actual vs. 2006 Board Approved, $457,337.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

The table below represents HCHI's actual capital spending for new meters for the meter change program and new services for the years 2004, 2005 and 2006 as well as capital spending for the conversion of general service customers using greater than 150 kW per month to an interval meter as funded through the third tranche funding from HCHI's Conservation and Demand Management program. Also included in the table below is additional capital spending in each of these three years for the installation of wholesale meters at the three HONI transformer stations; Jarvis TS, Caledonia TS, and Dunnville TS. Market rules dictated that HCHI be responsible for the wholesale metering which involved installation of primary metering units on each feeder exiting the TS and securing the services of a Meter Service Provider. The amount included in the 2006 Board Approved year as a Rate Base Tier 1 Adjustment for these wholesale meter upgrades in accordance with the rate model was under estimated by approximately $42,500. As well, the total spending for this period will be slightly greater than the variance between the 2006 Board Approved and the 2006 Actual due to the averaging of the 2003 and 2004 actual amounts as recorded in the 2006 Board Approved year.

Meters detailed as follows:

Meter Project	2004	2005	2006	Total
Single Phase Metering	6,158	49,833	22,784	78,775
Three Phase Metering	3,981	20,836	16,015	40,832
Meters - Miscellaneous		3,904		3,904
Interval Meter – CDM Program		5,022	9,885	14,907
Wholesale Meter – Jarvis PMU	300,117	2,531		302,648
Wholesale Meter – Caledonia PMU		55,273	145,893	201,166
Wholesale Meter - Dunnville PMU			101,647	101,647
Total Meter Projects	310,256	137,399	296,224	743,879

- **Account 1908 – Buildings**

2006 Actual vs. 2006 Board Approved, $357,521.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

Investments in 2005 include the following:

- Installation of air conditioning in the server room to ensure the server is kept at 68 degrees Fahrenheit, the area is ventilated and monitored to ensure that excessive heat does not affect the equipment - $10,323
- Installation of an exhaust system for the garage and stores areas. This system will be on timers and sensors to ensure that carbon monoxide, from truck and lift truck exhaust, cannot build up in these areas - $32,136

- Installation of a new septic system – required due to system failure - $33,006
- New eaves trough and down spouts required for the service centre building at Greendale Drive, Caledonia - $17,325

Investments in 2006 include the following:

- Implementation of a new telephone system which enabled HCHI to meet the OEB's reporting requirements and to provide better service to our customers - $12,520
- Additional Outdoor Security – Video Surveillance (3 cameras) - $5,539
- Building Renovations to rebuild the front lobby and customer service area was required to bring these areas up to modern professional business standard appearances and to provide a functional and ergonomic work environment for staff. Included in the renovation were new carpet, wall construction, and new heating & air conditioning system. Several times in 2004 the A/C system failed and was unable to maintain an appropriate temperature leaving it very uncomfortable for staff - $184,987

No other Projects for 2005 and 2006 exceeded materiality threshold.

- **Account 1920 – Computer Equipment - Hardware**

2006 Actual vs. 2006 Board Approved, $178,502.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

Investments in 2005 include the following:

- Installation of a new server to separate the financial software, Great Plains, from the billing software, CIS – Advanced; includes hardware, installation fees, and a snap appliance for network back-up - $53,164
- Replacement of computers and monitors in various departments as part of HCHI's annual scheduled program - $28,928

Investments in 2006 include the following:

- Replacement of computers and monitors in various departments as part of HCHI's annual scheduled program - $29,254
- Improvements to the corporate computer network in terms of reliability, with the replacement of the mail server, devices to better improve HCHI's remote monitoring and storage devices for file management - $40,398
- Addition of engineering tools in terms of rugged lap tops and mobile mappers to enable the collection of field data in electronic format. This data is then downloaded into the GIS - $5,550

No other Projects for 2005 and 2006 exceeded materiality threshold.

- **Account 1925 – Computer Equipment - Software**

2006 Actual vs. 2006 Board Approved, $506,126.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

Investments in 2005 include the following:

- Continuation of HCHI's mapping work to include gathering field GPS and attribute data on distribution system assets - $175,976
- Modifications to the CIS billing system; including CIS Scheduler setup, Deregulation upgrades and Bill Print modifications - $29,930
- Upgrade Great Plains financial software to current version 8.0 for added capabilities - $14,907

Investments in 2006 include the following:

- Continuation of HCHI's mapping work including a new land base map (aerial photo) and a streetlight audit to determine streetlight attribute data such as the exact type of light along with wattage; costs shared by Haldimand County - $112,313
- Updates to CIS billing system for regulatory requirements and Bill print modifications - $15,066
- Great Plains financial software - additional module purchases – Human Resources, Smart List Builder, and Purchase Order Processing - $22,063
- Purchase of back-up software for the corporate network - $13,362

No other Projects for 2005 and 2006 exceeded materiality threshold.

- **Account 1930 – Transportation Equipment**

2006 Actual vs. 2006 Board Approved, $171,567.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

Investments in 2005 include the following:

- Replacement of an Engineering pickup truck, 1997 Ford F150, with 263,000 kms and a poorly operating transmission. Purchase of a 2005 Chevrolet Silverado LS pickup - $36,649

Investments in 2006 include the following:

- In 2006 a long-term plan was established for the replacement of trucks extending to the year 2020. The replacement schedule was based on a large truck lasting about 15 years and small truck lasting 8 years. This time frame can be extended or shortened depending on the condition of the vehicle; high / low mileage, light / heavy usage or change in work function. The long-term goal of HCHI's truck replacement program is to replace vehicles at a rate which levels the expenditures from year to year and avoids the peaks and valleys of spending when only short-term needs are considered. Replacing the large fleet vehicles is an expensive proposition and it is critical that a schedule be maintained to avoid an extraordinary expenditure in any given year. Three vehicles were scheduled for replacement in 2006;

    1. Replacement of two pickup trucks that have high mileage and maintenance costs. Both are utilized as large truck accessory vehicles and typically carry material to & from job sites. Also used as on call trucks and are often the first ones utilized in responding to off hours trouble calls. (1999 4 X 4 GMC 2500 & 2000 4 X 4 GMC 2500) Purchase of two 2006 Chevrolet Silverado 2500 pickup trucks - $99,438

    2. Replacement of a light duty dump truck, 1990 GMC Sierra 1 Ton, due to age and poor condition of body, seats, and brakes. Purchase of a 2006 Ford F550 complete with DEL steel dump body - $61,538

- **Account 1940 – Tools, Shop and Garage Equipment**

2006 Actual vs. 2006 Board Approved, $89,532.

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 activity.

Investments in 2005 include the following:

- Purchase of tools such as voltage detectors, compression tools, underground locates device, phase testers, grounding sets, rubber protective cover, and other miscellaneous tools - $28,772

Investments in 2006 include the following:

- Purchase of tools such as overhead grounding set, digital recording ammeters, battery powered cable cutters, grounds jumper tester, battery operated crimping tool, 120 V house to house jumpers, high voltage testing kit, infrared thermometer and other miscellaneous tools - $34,177

- **Account 1995 – Contributions and Grants - Credit**

2006 Actual vs. 2006 Board Approved, $(1,086,832).

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such, the amount for 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as any capital contributions from customers in 2005 and 2006. Another contributing factor to the large variance is how the amount was reported in the 2006 Board Approved year; reported net of accumulated amortization on the closing balance in contributed capital. The years actual 2006, 2007, and 2008 and the 2009 bridge and 2010 test years have all been reported as gross

contributions with the accumulated amortization recorded in the appropriate USoA account. For an accurate comparison, the 2006 Board Approved amount should be reported with an ending balance of $(960,555) in account 1995 Contributions and $86,010 in 2105 Accumulated Amortization. This reallocation between actual contributions and the accumulated amortization on those contributions results in a revised variance amount between the 2006 Board Approved and the 2006 Actual of $(1,000,822).

One additional factor contributing to the variance is capital contributions from developers for subdivision development in 2005 and 2006 whereas there were not any recorded in the 2006 Board Approved year. Five evaluations were completed for subdivisions in 2005 and two evaluations in 2006. The net capital contribution from the developers contributing to the variance has been $(350,097) in 2005 and $(73,506) in 2006. The offsetting capital addition was recorded in the appropriate capital asset account for each year.

The table below represents HCHI's actual contributed capital detailed by asset type for the years 2004, 2005 and 2006. The total contributions for this period will be slightly greater than the variance between the 2006 Board Approved and the 2006 Actual due to the averaging of the 2003 and 2004 actual amounts as recorded in the 2006 Board Approved year.

Contributed Capital – Asset Type	2004	2005	2006	Total
Poles / Towers / Fixtures	(36,111)	(42,520)	(43,848)	(122,479)
Overhead Conductors and Devices	(3,197)	(5,369)	(635)	(9,201)
Underground Conduit	(29,565)	(31,549)	(21,596)	(82,710)
Underground Conductors and Devices	(73,560)	(320,214)	(105,214)	(498,988)
Line Transformers	(20,225)	(98,193)	(128,901)	(247,319)
Services	(52,426)	(34,108)	(40,311)	(126,845)

Contributed Capital – Asset Type	2004	2005	2006	Total
Meters	(5,787)	(4,609)	(13,319)	(23,715)
Total Capital Contributions	(220,871)	(536,562)	(353,824)	(1,111,257)

2007 Actual vs. 2006 Actual:

- **Construction Projects - Accounts as follows:**
  - **1830 – Poles, Towers & Fixtures $664,216**
  - **1835 – Overhead (O/H) Conductors and Devices $522,891**
  - **1840 – Underground (U/G) Conduit $16,190**
  - **1845 – Underground (U/G) Conductors and Devices $348,757**
  - **1850 – Line Transformers $480,031**

2007 Actual vs. 2006 Actual, $2,032,085.

The table below represents HCHI's actual investment in construction projects for the year 2007. The major contributing factor to this variance is the capital project "Line to Supply Hagersville from Jarvis" which was identified originally as a two phase project (2007 & 2008) but actually required three years to complete. (total approximate cost of $2,600,000). This project was required when HONI informed HCHI that it was necessary to move HCHI's load off of the HONI feeder, 27M3, at the Caledonia Transformer Stations (TS). HONI's studies showed that the Caledonia 27M3 will require load relief due to their requirement for increased load on the feeder in the near future. Loading was at 20 MW or 417 amps in the summer of 2005. Feeder relief is required once a feeder reaches 80% of its capacity at peak and 50% of its capacity on average. This is necessary to maintain transfer capability between feeders when system problems dictate a load transfer and when required maintenance is performed. Once the average loading of feeders exceeds 50% it becomes increasingly difficult to transfer load to alternate feeders. The goal is to maintain loading to allow transfers to

take place under average conditions. Detail on this project is contained in the project descriptions for 2007.

Construction projects detailed as follows:

Construction Projects	Poles, Towers & Fixtures (1830)	O/H Conductor & Devices (1835)	U/G Conduit (1840)	U/G Conductors & Devices (1845)	Line Transformers (1850)	Total
Project #1	142,916	236,274			32,076	411,266
Project #2	108,991	131,727			42,660	283,378
Project #3			4,741	3,857	68	8,666
Project #4			8,648			8,648
Project #5	107,892	5,328	2,280	1,969		117,469
Project #6	1,437	2,265			7,697	11,399
Project #7				236,003	82,952	318,955
Betterments	80,454	42,268	181	106,595	63,380	292,878
Line Extensions	222,526	105,029	341	332	251,198	582,426
USoA Total	664,216	522,891	16,191	348,756	480,031	2,032,085
Total Investment 2007	2,032,085					

2007 Specific Construction Projects

Project # 1 Line to Supply Hagersville from Jarvis TS – Phase 1
Type of Project Customer Demand
Amount of Project $411,266
Description of Project

HONI informed HCHI that it was necessary to move HCHI's load off of the HONI feeder, the 27M3, at the Caledonia Transformer Station (TS). HONI's studies showed that the Caledonia 27M3 will require load relief due to their (HONI) requirement for increased load on the feeder in the near future. Loading was at 20 MW or 417 amps in the summer of 2005. Feeder relief is required once a feeder reaches 80% of its capacity at peak and 50% of its capacity on average. This is necessary to maintain transfer

capability between feeders when system problems dictate a load transfer and when required maintenance is performed. Once the average loading of feeders exceed 50% it becomes increasingly difficult to transfer load to alternate feeders. The goal is to maintain loading to allow transfers to take place under average conditions.

Completing this project involves rebuilding or installing new line for 10.55 km along Hwy 6 from just south of Hagersville to south of Jarvis. The existing 8.3kV load on Hwy 6 and along laterals running down Concession roads will be converted to 27.6kV. A section of conductor on Parkview Road in Hagersville will be upgraded to a larger conductor size.

This is a multi-year project.

Business Value	Comments
Reliability/Performance	The existing supply (the 27M3) is primarily off road and is very difficult to patrol and maintain. Changing HCHI's supply to a feeder which is easier to patrol and maintain will increase reliability. Changing to a feeder owned and operated by HCHI will increase reliability because the service provider is local. The new line will provide an interconnection point (where none existed before) between two HONI stations (Jarvis TS & Caledonia TS) which can be switched to get customers back on faster increasing reliability. The communities along this line (Hagersville, Jarvis, and Townsend) will now have two supply points. The customers fed from the Jarvis DS (8.3kV station) will be transferred to a 27kV primary feed which should increase their reliability. Conversion of this long line reduces line losses increasing performance. This line will allow HCHI to avoid paying sub-transmission charges potentially increasing economic performance.
Community Relations	Co-operating with HONI to strengthen the grid is a positive action.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident. Having one service provider reduces the risk of an incident.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 2 Elimination of Long-Term Load Transfers Haldibrook Road & McClung,Caledonia, Haldibrook Road & Hwy 6, Caledonia, Hwy 3 West at Norfolk Boundary, Concession 17 & Haldimand Road 20, Walpole
Type of Project Regulatory
Amount of Project $283,378
Description of Project

See comments under Project # 5 in 2004

Project # 3 Replace Defective Transformer Pads – Various Locations
Type of Project Sustainment
Amount of Project $8,666
Description of Project

See comments under Project # 3 in 2004

Project # 4 Junction Vault J19 – Highland & McMaster, Caledonia
Type of Project Sustainment
Amount of Project $8,648
Description of Project

This project involves changing a primary pad-mounted junction box.

Business Value	Comments
Reliability/Performance	The existing junction box has corroded to a point where it is no longer secure. Replacement will increase reliability.
Community Relations	No Impact.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident. Perforation of the exterior of this junction box may create gaps which are large enough to allow children to poke sticks or reach inside is a potentially serious electrical hazard. Replacement eliminates the risk.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 5 Hawk Road Rebuild – Stelco Industrial Park, Phase 2, Nanticoke
Type of Project Sustainment
Amount of Project $117,469
Description of Project

This project was partially carried over from 2005. See comments under Project # 6 in 2006.

Project # 6 Eliminate Forest Street 4.16kV Distribution Station (DS) – Dunnville
Type of Project Sustainment
Amount of Project $11,399
Description of Project

This project was partially carried over from 2006. See comments under Project # 4 in 2005.

Project # 7 Subdivisions – Assumption of Assets (3 subdivisions)
Amount of Project $318,955

This capital project represents the assets assumed two years after the year serviced for 3 subdivisions within Haldimand County less the offsetting rebate to each developer, the amount of which is shown as contributed capital.

2007 Other Projects

Betterments

In addition to what has been described earlier under the description for 2004, 2005, and 2006 additional expenditures in this category include upgrades required to correct hazards identified during the distribution system inspection process. Generally these expenses are incurred to correct substandard line clearances to buildings and structures. These types of corrections are reported to the Electrical Safety Authority as such hazards.

Line Extensions

See description under 2004, 2005, and 2006 Other Projects.

- **Account 1855 – Services**

2007 Actual vs. 2006 Actual, $199,879.

See description under 2004, 2005, and 2006 Other Projects.

Services, new and upgraded, detailed as follows:

2007 Service	Upgrade Overhead	Upgrade Underground	New	Total
<= 200 Amp, Single Phase	64,670	124,658		189,328
> 200 Amp, Single Phase	5,179	321		5,500
<= 200 Amp, Three Phase		125		125
> 200 Amp, Three Phase	3,554			3,554
New - Miscellaneous			1,372	1,372
Total Services	73,403	125,104	1,372	199,879

- **Account 1860 – Meters**

2007 Actual vs. 2006 Actual, $71,178.

The table below represents HCHI's actual capital spending for new meters for new services and meters and equipment to start converting approximately 1,200 A-Base meters to S-Base meters with appropriate adapters. This work was planned to be completed in preparation of mass smart meter deployment. This also includes the final capital spending for the conversion of general service customers using greater than 150 kW per month to an interval meter as funded through the third tranche funding from

HCHI's Conservation and Demand Management program. Also included in the table below is additional capital spending to complete the upgrade at the Caledonia TS to a wholesale meter.

Meters detailed as follows:

2007	Single Phase Metering	Three Phase Metering	Interval Meter – CDM Program	Wholesale Meter – Caledonia PMU
Meter Services	19,234	17,022	10,358	24,564
Total Meter Projects	71,178			

- **Account 1908 – Buildings**

2007 Actual vs. 2006 Actual, $456,857.

Various renovations and system upgrades to the building at Greendale Drive, Caledonia occurred in 2007. Details as follows:

- Final implementation of a new telephone system which enabled HCHI to meet the OEB's reporting requirements and to provide better service to our customers. Project began in 2006 - $53,464
- The completion of the building renovations for the customer service area which began in 2006 - $187,342.
- Additional HVAC for Server and Telephone room including relocation of an air distribution system and the removal of a wall - $22,650
- Repaving area 3 of the parking lot and installing compacted backfill to enable a previously unused portion of the warehouse yard to be utilized as extra storage space - $51,789
- Building Renovations to rebuild the executive and finance area and update the operations area was required to bring these areas up to modern

professional business standard appearances and to provide a functional and ergonomic work environment for staff. Included in the renovation was new carpet, wall construction, ceiling reconstruction, and updating the washrooms.. - $137,880

No other Projects for 2007 exceeded materiality threshold.

- **Account 1925 – Computer Equipment - Software**

2007 Actual vs. 2006 Actual, $335,441.

In 2007 investments were targeted for the ESRI Distribution Mapping System, the upgrade to the CIS billing system, version upgrade to the financial software, renewal of the Software Assurance Microsoft licensing (two year renewal), and additional security patches.

Investments in 2007 as follows:

- Continuation of HCHI's mapping work to include gathering field GPS and attribute data on distribution system assets - $183,504
- In 2007, Advanced Utility Billing Systems announced that they would be leaving the Ontario market. HCHI reviewed options and selected a customer information system. The 2007 costs represent the initial stages of conversion to the selected CIS billing system - $28,127
- Great Plains financial software - upgrade to current version 10.0 for added capabilities - $26,737
- Microsoft BakBone activation licensing for servers and end users, ArcGIS ESRI Server licenses, and AutoCAD licenses - $64,788

No other Projects for 2007 exceeded materiality threshold.

- **Account 1915 – Office Furniture and Equipment**

2007 Actual vs. 2006 Actual, $73,266.

Additional investments were made in 2007 for ergonomic workstations. These investments are detailed as follows:

- Customer Service workstations, keyboard arms and trays, mouse platforms, and mobile desk in customer service area - $73,300

- **Account 1940 – Tools, Shop and Garage Equipment**

2007 Actual vs. 2006 Actual, $62,743.

HCHI's 2007 investments in tools and measuring equipment used in the execution of everyday tasks are detailed as follows:

- Purchase of hydraulic cable cutters, 200 ft house to house jumpers, VON ServiSavor power restoration device, transformer / pole dolly, capstan hoist, Grid Sense line trackers, ground cover mats, Medtronic defibrillators, and ground resistance tester - $62,743

- **Account 1995 – Contributions and Grants - Credit**

2007 Actual vs. 2006 Actual, $(472,830).

Contributing factors to HCHI's capital contributions are line extensions for new services, contributions from developers for subdivision development, and contributions required from existing customer upgrades as per HCHI's Conditions of Service. Three evaluations were completed for subdivisions in 2007. The net capital contribution from the developers contributing to the variance is shown separately in the table below. The offsetting capital addition was recorded in the appropriate capital asset account for each year.

The table below represents HCHI's actual contributed capital detailed by asset type for the year 2007.

Contributed Capital – Asset Type	New Service / Line Extension	Subdivision	Total
Poles / Towers / Fixtures	(88,323)		(88,323)
Overhead Conductors and Devices	(17,374)		(17,374)
Underground Conduit	(22,932)		(22,932)
Underground Conductors and Devices	(38,522)	(134,648)	(173,170)
Line Transformers	(48,561)	(43,848)	(92,409)
Services	(66,542)		(66,542)
Meters	(12,080)		(12,080)
Total Capital Contributions	(294,334)	(178,496)	(472,830)

2008 Actual vs. 2007 Actual

- **Account 1820 – Distribution Station Equipment**

2008 Actual vs. 2007 Actual, $197,835.

The variance in this account is solely due to capital work performed in 2008 not performed in prior years. The capital projects contributing to this variance are as follows:

Decewsville Distribution Station – Transformer Replacement

- Oil testing determined that the insulation in these transformers had deteriorated to a point where they were beyond repair. It was recommended that these transformers be taken out of service at the earliest possible date. Therefore, it was necessary to purchase a transformer with enough capacity to satisfy the load in the station and be a

match for capacities in other stations. The current spares were only 2 MVA in capacity and 5 MVA is required to match the current station standard. This capital project involved replacing the existing 3 transformers with one new unit and the costs have been netted with the disposal of the old transformers - $166,635

HONI Wholesale Meter Points (3 PMU's)

- This was the reclassification of HONI's exit fees that were charged when the wholesale metering was upgraded / acquired at the three transformer stations; Jarvis TS, Caledonia TS, and Dunnville TS. These exit fees were previously recorded as expenses and only reclassified to capital when the OEB issued the August 2008 FAQ's to the APH (question #15). The amount is calculated based on two exit fees at each TS - $31,200

- **Construction Projects - Accounts as follows:**
  - **1830 – Poles, Towers & Fixtures $1,410,907**
  - **1835 – Overhead (O/H) Conductors and Devices $1,243,981**
  - **1840 – Underground (U/G) Conduit $108,415**
  - **1845 – Underground (U/G) Conductors and Devices $96,986**
  - **1850 – Line Transformers $877,688**

2008 Actual vs. 2007 Actual, $3,737,977.

The table below represents HCHI's actual investment in construction projects for the year 2008. As discussed in the 2007 Actual years construction projects, the major contributing factor to this year's variance is the expenditure for the capital project "Line to Supply Hagersville from Jarvis, Phase 2" (total approximate cost of $2,600,000). A little more than half of this value is recorded as capital in the 2008 Actual year; approximately $1,400,000. Another contributing factor to this variance resides in the Line Transformer account 1850 of approximately $183,000. This represents the value of transformers that have been reclassified from inventory to spare capital inventory

according to the OEB's APH Article 410, section titled "Change in Accounting Policy for Spare Transformers and Meters". These transformers have been identified as the spare or reserve transformers held at HCHI's warehouse that provide a future benefit as they are expected to be placed into service at some point and enhance the system reliability of the original distribution plant.

Construction projects detailed as follows:

Construction Projects	Poles, Towers & Fixtures (1830)	O/H Conductor & Devices (1835)	U/G Conduit (1840)	U/G Conductors & Devices (1845)	Line Transformers (1850)	Total
Project #1	644,168	578,718			186,030	1,408,916
Project #2	153,936	99,808	1,522		47,640	302,906
Project #3	103,384	41,616				145,000
Project #4	83,678	260,603			194,903	539,184
Project #5	12,607	4,422	57,940	949		75,918
Project #6	6,383	10,749		702	2,637	20,471
Project #7					182,924	182,924
Project #8				78,771	5,892	84,663
Betterments	238,697	150,171	5,925	6,892	66,053	467,738
Line Extensions	168,054	97,894	43,028	9,672	191,609	510,257
USoA Total	1,410,907	1,243,981	108,415	96,986	877,688	3,737,977
Total Investment 2008	3,737,977					

2008 Specific Construction Projects

Project # 1 Line Supply - Hagersville from Jarvis TS – Phase 2
Type of Project Customer Demand
Amount of Project $1,408,916
Description of Project

See comments under Project # 1 in 2007

Project # 2 Pole Replacement Program, Various Locations
Type of Project Sustainment
Amount of Project $302,906
Description of Project

This project involves changing poles that have been tested and declared at the end of life. HCHI's maintenance and inspection program requires poles which are suspected of being at end of life to be tested for strength. If the pole fails the strength test it is scheduled for replacement.

Business Value	Comments
Reliability/Performance	The existing poles are at end of life and will not support the conductors under high load conditions. Replacement will increase reliability.
Community Relations	No Impact.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident.
Regulatory Intervention	No Impact.
Environmental Stewardship	No Impact.

Project # 3 Purchase of Line Sections 57M5 and Part of 57M3 from HONI - Walpole
Type of Project Purchase Asset
Amount of Project $145,000
Description of Project

Within the service territory of HCHI there are pole lines and circuits owned by HONI. These assets generally were retained by HONI after the sale of HONI assets to the LDC's in the late 1990's because they distributed power to HONI customers beyond HCHI's borders. This particular purchase involves poles, conductors, and devices which do not supply any HONI customers and therefore, are not required by HONI. The main benefit of this is the reduction of sub-transmission charges for use of HONI's distribution equipment for both HCHI and the Ontario Clean Water Agency (OCWA).

The OEB has approved this purchase – see decision and order dated February 28, 2008 – Order # EB-2007-0966.

Business Value	Comments
Reliability/Performance	Provides circuits for HCHI which can be used to re-configure HCHI's distribution system adding operational flexibility. Increased operational flexibility should increase reliability. Responsibility for maintenance and emergency response would change from HONI to HCHI increasing the speed of the response due to local presence.
Community Relations	No impact
Safety	No coordination of emergency repairs would have to be made by HCHI which reduces the risk of an incident.
Regulatory Intervention	No impact.
Environmental Stewardship	No impact.

Project # 4 Elimination of Nanticoke DS, Walpole
Type of Project Sustainment
Amount of Project $539,184
Description of Project

Nanticoke DS located in the rural area of Walpole was installed in approximately 1950 and consisted of a station transformer and open steel structure. This equipment had exceeded its design life. This project involves changing the 8.3kV distribution equipment along a 12km section of 27.6kV line and eliminate the need for the DS.

Business Value	Comments
Reliability/Performance	Station exceeding its design life of 40 years and transformer insulation has been identified as needing a dry out. Replacing the station with new distribution equipment will increase reliability. Eliminating the station will eliminate the need to spend money on maintenance activities. Converting to a higher voltage supports reduced losses.
Community Relations	
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This reduces the risk of an incident.
Regulatory	No Impact

Intervention	
Environmental Stewardship	The station is in a rural area with drainage ditches and it had no oil containment provisions. Risk of a spill to a water course was low to medium.

Project #5 Hawk Road Rebuild - Stelco Industrial Park, Phase 3, Nanticoke
Type of Project Sustainment
Amount of Project $75,918
Description of Project

This project was partially carried over from 2005. See comments under Project # 6 in 2006.

Project#6 Elimination of Long-Term Load Transfers at Haldibrook Rd. & McClung Rd., Haldibrook Rd. & Hwy. #6, Hwy. #3 West at Norfolk Boundary, and Concession #17 & Haldimand Rd. #20
Type of Project Regulatory
Amount of Project $20,471
Description of Project

See comments under Project # 5 in 2004

Project #7 Reallocation of Spare Transformer Capital
Amount of Project $182,924

As mentioned in the variance summary above for 2008 capital construction projects, this amount represents the value of spare transformers reallocated from inventory to capital as the OEB's APH Article 410.

Project #8 Subdivisions – Assumption of Assets (2 subdivisions)
Amount of Project 84,663

This capital project represents the assets assumed two years after the year serviced for 2 subdivisions within Haldimand County less the offsetting rebate to each developer, the amount of which is shown as contributed capital.

2008 Other Projects

Betterments and Line Extensions

See description under 2007's discussion..

- **Account 1855 – Services**

2008 Actual vs. 2007 Actual, $137,005.

See description under 2004, 2005, and 2006 Other Projects.

Services, new and upgraded, detailed as follows:

2008 Service	Upgrade Overhead	Upgrade Underground	New	Total
<= 200 Amp, Single Phase	51,561	75,740		127,301
> 200 Amp, Single Phase	2,466	674		3,140
<= 200 Amp, Three Phase		367		367
> 200 Amp, Three Phase	162	521		683
New - Miscellaneous			5,514	5,514
Total Services	54,189	77,302	5,514	137,005

- **Account 1860 – Meters**

2008 Actual vs. 2007 Actual, $84,101.

The table below represents HCHI's actual capital spending for new meters for new services and continuation of A-Base conversion work. Also included in the table below, similar to Line Transformer account 1850, is a value for meters that have been reclassified from inventory to spare capital inventory according to the OEB's APH Article 410, section titled "Change in Accounting Policy for Spare Transformers and Meters".

These meters have been identified as spare or reserve meters held at HCHI's warehouse that provide a future benefit as they are expected to be placed into service at some point and enhance the system reliability of the original distribution plant. The majority of the value of these spares is for Primary Metering Unit's (PMU's). The IESO Emergency Instrument Transformer Restoration Plan (EITRP) identifies the need and requirement to have spare equipment.

Meters detailed as follows:

2008	Single Phase Metering	Three Phase Metering	Spare Meter Capital
Meter Services	15,301	43,123	25,677
Total Meter Projects	84,101		

- **Account 1908 – Buildings**

2008 Actual vs. 2007 Actual, $83,776.

Various renovations and upgrades to the building at Greendale Drive, Caledonia occurred in 2008. Details as follows:

- The remaining portion of the warehouse yard (which was filled and compacted in 2007) was completely paved - $50,000

No other Projects for 2008 exceeded materiality threshold.

- **Account 1925 – Computer Equipment - Software**

2008 Actual vs. 2007 Actual, $606,533.

In 2008 a significant portion of the capital investment was comprised of the installation of a new CIS billing system and the continued development of the ESRI Distribution mapping system.

Investments in 2008 as follows:

- Continuation of HCHI's mapping work as in past years; gathering field data, tie of locates to mapping system, and to work towards automated Performance Service Indicators - $190,148
- Continuation of the installation of the CIS billing system - Harris Northstar; including the core design and implementation - $403,053

No other Projects for 2008 exceeded the materiality threshold.

- **Account 1940 – Tools, Shop and Garage Equipment**

2008 Actual vs. 2007 Actual, $54,509.

HCHI's 2008 investments in tools and measuring equipment used in the execution of everyday tasks are detailed as follows:

- Purchase of load buster tools, insulated live line cutters, 3-phase line trackers, meter base logger, and walk behind floor sweeper - $54,509

- **Account 1995 – Contributions and Grants - Credit**

2008 Actual vs. 2007 Actual, $(242,212).

Contributing factors to HCHI's capital contributions are line extensions for new services, contributions from developers for subdivision development, and contributions required from existing customer upgrades as per HCHI's Conditions of Service. Two evaluations were completed for subdivisions in 2008. The net capital contribution from the developers contributing to the variance is shown separately in the table below. The offsetting capital addition was recorded in the appropriate capital asset account for each year. In account 1835, Overhead Conductors and Devices, there is a net charge balance instead of the customary credit. This is the result of a rebate back to a customer who contributed to a line extension in 2003. The rebate was granted based on an economic evaluation performed for an additional connection in 2008 to this line

extension. There was little activity in the Contributed Capital Overhead Conductors and Devices, $(1,545), which netted to a charge in the account when the rebate, $2,662, was processed. An additional portion of the rebate was also charged to Contributed Capital – Poles Towers & Fixtures but there was enough credit activity to offset the charge, resulting in a remaining credit balance in the contribution account.

The table below represents HCHI's actual contributed capital detailed by asset type for the year 2008.

Contributed Capital – Asset Type	New Service / Line Extension	Subdivision	Total
Poles / Towers / Fixtures	(30,424)		(30,424)
Overhead Conductors and Devices	1,117		1,117
Underground Conduit	(28,078)		(28,078)
Underground Conductors and Devices	(27,928)	(28,382)	(56,310)
Line Transformers	(43,630)	(2,045)	(45,675)
Services	(70,471)		(70,471)
Meters	(12,371)		(12,371)
Total Capital Contributions	(211,785)	(30,427)	(242,212)

2009 Bridge Year vs. 2008 Actual:

- **Construction Projects - Accounts as follows:**
  - **1830 – Poles, Towers & Fixtures $804,807**
  - **1835 – Overhead (O/H) Conductors and Devices $1,334,259**
  - **1840 – Underground (U/G) Conduit $234,685**
  - **1845 – Underground (U/G) Conductors and Devices $136,976**
  - **1850 – Line Transformers $632,358**

2009 Bridge vs. 2008 Actual, $3,143,085.

The table below represents HCHI's projected investment in construction projects for the bridge year 2009. As discussed in the 2007 Actual and 2008 Actual years construction projects, the major contributing factor to this year's variance is the capital project "Line to Supply Hagersville from Jarvis, Phase 3" (total approximate cost of $2,600,000). Another contributing factor to the variance is the pole replacement program initiated in 2008. The capital investment for this project for 2009 has increased over the 2008 investment.

Construction projects detailed as follows:

Construction Projects	Poles, Towers & Fixtures (1830)	O/H Conductor & Devices (1835)	U/G Conduit (1840)	U/G Conductors & Devices (1845)	Line Transformers (1850)	Total
Project #1	50,800	45,400			51,800	148,000
Project #2	250,298	162,286	2,474		77,462	492,520
Project #3	92,754	556,312			113,222	762,288
Project #4	14,800	87,900	3,000	11,800	17,500	135,000
Project #5	13,500	14,500	206,000	57,500	55,000	346,500
Project #6	101,000	113,500		14,000	66,500	295,000
Project #7		200,000				200,000
Betterments	101,019	59,886	1,710	48,731	46,020	257,366

Construction Projects	Poles, Towers & Fixtures (1830)	O/H Conductor & Devices (1835)	U/G Conduit (1840)	U/G Conductors & Devices (1845)	Line Transformers (1850)	Total
Line Extensions	180,636	94,475	21,501	4,945	204,854	506,411
USoA Total	804,807	1,334,259	234,685	136,976	632,358	3,143,085
Total Investment 2009	3,143,085					

2009 Specific Construction Projects

Project # 1 Moulton-Sherbrooke Townline – Rattlesnake Road Conversion, Moulton/Sherbrooke
Type of Project Reliability
Amount of Project $148,000
Description of Project

This project involves the installation of step down transformers and changing the primary supply from 8.3kV to 27.6kV.

Business Value	Comments
Reliability/Performance	This area has been subject to low voltage over the last two years. The feeder has a large phase to phase loading imbalance which cannot be corrected due to the layout of the distribution system. Low voltage occurs at peak loading during the summer peaks of June, July, and August. Converting the area will eliminate the imbalance on the 8.3kv F3 feeder from Dunnville DS and correct the low voltage.
Community Relations	Will eliminate low voltage complaints.
Safety	Low voltage complaints always require intervention by HCHI field staff. Corrective actions usually involve changing transformer taps or reconfiguring the circuits temporarily to improve voltage. Eliminating the need to take corrective action will remove the risk of an incident.
Regulatory Intervention	During low voltage periods it is conceivable that the Electrical Safety Authority could intervene to order HCHI to take corrective actions to improve the voltage. Taking a proactive approach reduces the risk of intervention.
Environmental Stewardship	No impact.

Project # 2 Pole Replacement Program, Various Locations
Type of Project Sustainment
Amount of Project $492,520
Description of Project

At the time of setting the budget for 2009 there were 446 outstanding defective poles to be replaced. The number of poles to be replaced per annum was increased from 90 in 2008 to 140 in 2009. HCHI's strategy is to replace all known defective poles in an inspection area before the next inspection cycle. The number of defective poles represents poles in the first three of five areas of inspection. If 140 poles are replaced annually over a three year period most of the 446 poles will be replaced before the first area of inspection is due for its second cycle of inspections. This also levels the expenditure to approximately $500,000 per annum.

See comments under Project # 2 in 2008.

Project # 3 Line Supply - Hagersville from Jarvis TS – Phase 2
Type of Project Customer Demand
Amount of Project $762,288
Description of Project

See comments under Project # 1 in 2007.

Project # 4 Central Lane Phase II Conversion, Dunnville
Type of Project Sustainment
Amount of Project $135,000
Description of Project

This project involves completing a project started by the former Dunnville HEC but never finished. The existing plant will be upgraded to 27.6kV including some new poles, transformers, and conductor. This project supports HCHI's strategy to convert loads to 27.6kV distribution.

Business Value	Comments
Reliability/Performance	This area is currently fed from a step down transformer (27.6kV/4.16kV) and is a mixture of old and newer assets.

	Converting to 27.6kV will eliminate the need for the 4.16kV equipment and standardize on 27.6kV. The upgrade will enhance reliability due to increased clearances and new equipment. The design also eliminates an inaccessible pole line on private property which will increase reliability as access is no longer an issue.
Community Relations	The area was partially rebuilt in the 1970's but was never completed. As a result there are a number of old poles in various conditions and some would be considered temporary installations of equipment from old to new line. Eliminating the old assets will lessen the clutter of multiple poles on adjacent properties. The design also eliminates an inaccessible pole line on private property which will be viewed by the public as a positive step.
Safety	The risk of public safety will be improved by eliminating old assets. The risk to HCHI staff will be improved due to the elimination of temporary installations.
Regulatory Intervention	No impact.
Environmental Stewardship	No impact.

Project # 5 Lakeshore Road Re-build – Melville Lane, Rainham
Type of Project Sustainment
Amount of Project $346,500
Description of Project

The Lake Erie shoreline is home to many single property cottages and clusters of cottages with privately owned roads or lanes. Traditionally this area was inhabited seasonally, but in recent years there is a trend for developing all season properties. This area runs along the lake for approximately 60 km. The age of the assets in these areas is 50 to 60 years and much of it is installed in rear lots away from the travelled portion of the road. Due to its age the area is very well established with many encumbrances to our pole lines such as sheds, clothes lines, parked boats & cars, building materials, etc. This makes maintenance and restoration very inefficient and costly.

HCHI recognizes that these assets are approaching the end of life and due to the length of line along the lake asset replacement will need to be a long term program likely exceeding twenty (20) years in time. The basic strategy encompasses the following concepts:

a) Relocate primary and where possible secondary to roadways and laneways;
b) Utilize underground assets where necessary;
c) Minimize the impact to the customer when new assets are installed where there were none before.

The above project is the first of many and in some ways is a pilot project for the rest of the asset re-development along the lake. For this phase of the project concrete poles complete with conductor, and transformers will be installed along the lanes from the main Lakeshore Road. This will replace assets located in the rear lot. Re-building of the lakeshore is a multi-year project.

Business Value	Comments
Reliability/Performance	As the age of the assets increases the reliability will decrease with time. Access to rear lot always increases restoration times. Redeveloping will improve reliability and restoration time.
Community Relations	There will be a trade-off with increased reliability and the location of assets. Relocating assets from the rear lot and placing them on roadways will likely be opposed by some property owners.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards) and relocating from the rear lot. The risk to HCHI staff will be reduced due to better access, increased clearances of new designs, and elimination of deteriorated plant.
Regulatory Intervention	No impact
Environmental Stewardship	The close proximity to the lake makes a transformer oil spill a sensitive issue. Eliminating old plant will decrease the risk.

Project # 6 Eliminate Selkirk North 8.3kV Distribution Station (DS) – Caledonia
Type of Project Sustainment
Amount of Project $295,000
Description of Project

This DS located in the community centre of Caledonia was installed in approximately 1952 and consists of a station transformer and open steel structure. This project involves rebuilding an existing pole line to connect the station to the 27M5 circuit and converting an existing 8.3kV line to 27.6kV. In the conversion a number of transformers will be upgraded to 27.6kV. This project supports HCHI's strategy of reducing sub-transmission charges from HONI, the transfer of loads to 27.6kV distribution, and the elimination of 8.3kV distribution stations.

Business Value	Comments
Reliability/Performance	Selkirk North DS has station transformers built in 1952 which have exceeded their life cycle. In recent years faults occurring at this station have contributed to the deterioration of the transformer bushings. Rondar Inc. (an electrical service firm) has recommended the replacement of the bushings in the near future. Elimination of this station will increase reliability.
Community Relations	The existing station is in a residential area and disposing of the station will likely clear the way for more residential development consistent with the surrounding area. A positive step.
Safety	Elimination of assets at the end of their lifecycle will increase safety for the public and HCHI staff.
Regulatory Intervention	No impact
Environmental Stewardship	A breach in the station transformer tanks could possibly lead to pollution in the Grand River which is 124 meters away. Elimination prevents this from happening.

Project # 7 Purchase HONI F2 Feeder out of Argyle Distribution Station – Caledonia
Type of Project Purchase Asset
Amount of Project $200,000
Description of Project

Within the service territory of HCHI there are pole lines and circuits owned by HONI. These assets generally were retained by HONI after the sale of HONI assets to the LDC's in the late 1990's because they distributed power to HONI customers beyond HCHI's borders. This particular circuit is an 8.3kV circuit fed from HONI's Argyle DS.

In 2007 HONI informed HCHI that all IESO metering points between HONI and HCHI would not be brought up to current IESO standards. A solution was therefore required to either eliminate the metering point or change the type of billing to a retail account. In this case it was proposed that with little effort the metering point could be eliminated if HONI would sell its assets within HCHI's service territory and provide step down transformation at the border to accommodate HONI customers. The main benefit of this is to improve reliability and operational flexibility but in time it will facilitate conversion to 27.6kV and reduce the sub-transmission charges for use of HONI's distribution equipment. The OEB has approved this purchase – Decision and Order dated May 15, 2009 (EB-2009-0136).

Business Value	Comments
Reliability/Performance	Provides a path for HCHI to convert to 27.6kV in the future. Responsibility for maintenance and emergency response would change from HONI to HCHI increasing the speed of the response due to local presence.
Community Relations	No impact
Safety	No coordination of emergency repairs would have to be made by HCHI which reduces the risk of an incident.
Regulatory Intervention	No impact.
Environmental Stewardship	No impact.

2009 Other Projects

Betterments and Line Extensions

See description under 2007's discussion.

- **Account 1855 – Services**

2009 Bridge vs. 2008 Actual, $182,013.

See description under 2004, 2005, and 2006 Other Projects.

Services, new and upgraded, detailed as follows:

2009 Service	Upgrade Overhead	Upgrade Underground	New	Total
<= 200 Amp, Single Phase	82,715	86,548		169,263
> 200 Amp, Single Phase	3,956	770		4,726
<= 200 Amp, Three Phase		419		419
> 200 Amp, Three Phase	260	596		856
New - Miscellaneous			6,749	6,749
Total Services	86,931	88,333	6,749	182,013

- **Account 1925 – Computer Equipment - Software**

2009 Bridge vs. 2008 Actual, $420,105.

In 2009 the installation of the new CIS billing system was completed. As well, capital investment included ongoing development of the ESRI Distribution mapping system.

Investments in 2009 as follows:

- Continuation of HCHI's mapping work as in past years - $177,500

- Completion of the installation of the CIS billing system - Harris Northstar - $206,725

No other Projects for 2009 exceeded the materiality threshold.

- **Account 1930 – Transportation Equipment**

2009 Bridge vs. 2008 Actual, $586,656.

In 2008 an evaluation matrix was created to assist with prioritizing and identifying the order of truck replacements. The matrix uses six factors to assist with quantifying the status of each vehicle; age, mileage, type of service, reliability, maintenance & repair costs, and condition. In addition to the matrix the replacement of large trucks is spread over two years to accommodate the delivery schedules and time required to build the large trucks.

Investments in 2009 include the following:

- Replacement of a bucket truck, 1992 Double Bucket Single Axle, - Purchase of a 2009 International 7400 plus Altec Single Bucket - $236,617
- Replacement of an Operations pickup truck, 2002 Ford F150 4 X 4, with 234,615 km and maintenance & repair costs reaching 45% of the original purchase cost. Purchase of a 2009 Ford Escape Compact SUV - $30,000
- Purchase of a new reel/stringing trailer for installing field lashed secondary buss but also to be utilized for any other type of aerial conductor. The secondary stringing activity is performed regularly and the current setup uses two trailers which is not the most efficient use of the equipment - $28,239
- Replacement of a bucket truck, 1999 Single Bucket Man Lift (Chassis 1998), with 357,785 km that has been breaking down frequently resulting

in high repair costs. Purchase of a 2009 Single Bucket Man Lift - $200,000

- Replacement of a Radial Boom Derrick (RBD) truck, 1990 Single Bucket Pitman International, with 109,743 km experiencing frequent breakdowns and repairs. Purchase of a 2010 Radial Boom Derrick over a two year period – 2009 will be the chassis only - $91,800

- **Account 1940 – Tools, Shop and Garage Equipment**

2009 Bridge vs. 2008 Actual, $53,864.

HCHI's 2009 investments in tools and measuring equipment used in the execution of everyday work are detailed as follows:

- Purchase of a pressure washer, insulated cable cutters, ground resistance meter, hydraulic impact wrench & drill, VON ServiSavor, mechanical torque indicator for radial bucket device, line trackers (feeder & DS monitoring), and a portable power quality meter - $53,864

2010 Test Year vs. 2009 Bridge:

- **Construction Projects - Accounts as follows:**
  - **1830 – Poles, Towers & Fixtures $726,388**
  - **1835 – Overhead (O/H) Conductors and Devices $572,938**
  - **1840 – Underground (U/G) Conduit $364,927**
  - **1845 – Underground (U/G) Conductors and Devices $214,503**
  - **1850 – Line Transformers $515,365**

2010 Test vs. 2009 Bridge, $2,394,121.

The table below represents HCHI's projected investment in construction projects for the test year 2010.

Construction projects detailed as follows:

Construction Projects	Poles, Towers & Fixtures (1830)	O/H Conductor & Devices (1835)	U/G Conduit (1840)	U/G Conductors & Devices (1845)	Line Transformers (1850)	Total
Project #1	87,000	73,000				160,000
Project #2	13,500	14,500	168,000	49,000	55,000	300,000
Project #3	38,000	98,000		4,000	57,000	197,000
Project #4	22,500	11,000	170,000	36,500	60,000	300,000
Project #5	11,500	47,000		68,500		127,000
Project #6	257,839	167,176	2,549		79,796	507,360
Betterments	106,367	63,057	1,800	51,311	48,456	270,991
Line Extensions	189,682	99,205	22,578	5,192	215,113	531,770
USoA Total	726,388	572,938	364,927	214,503	515,365	2,394,121
Total Investment 2010	2,394,121					

2010 Specific Construction Projects

Project # 1 Eliminate 57M3 Supply Points – Concessions 12 to 17, Walpole
Type of Project Reliability
Amount of Project $160,000
Description of Project

Within the service territory of HCHI there are pole lines and circuits owned by HONI. These assets generally were retained by HONI after the sale of HONI assets to the LDC's in the late 1990's because they distributed power to HONI customers beyond HCHI's borders. This particular project involves eliminating supply points from the 57M3 HONI circuit from Jarvis TS by building pole lines to connect existing distribution lines where there are physical separations between HCHI lines fed from HCHI feeders and HCHI lines fed from HONI's feeders. The HONI supply points will be eliminated. This project supports HCHI's strategy of eliminating sub-transmission charges.

Business Value	Comments
Reliability/Performance	Changing the supply point to a HCHI controlled feeder will increase reliability because the circuit exposure outside of HCHI's territory will be eliminated. It also increases response time due to local presence of HCHI staff.
Community Relations	Customers in this supply area are fully aware of being supplied from a HONI feeder and that their LDC must wait for HONI staff to arrive before a repair can be made or coordinated. The transfer of supply point will eliminate a HONI response.
Safety	No coordination of emergency repairs would have to be made by HCHI which reduces the risk of an incident.
Regulatory Intervention	No impact.
Environmental Stewardship	No impact.

Project # 2 Lakeshore Road Re-build – Rainham
Type of Project Sustainment
Amount of Project $300,000
Description of Project

See comments under Project # 5 in 2009.

Project # 3 Conversion to Supply Innophos Canada Inc. (HCHI Large Customer) and Sherbrooke Area to 31M1 Feeder, Moulton
Type of Project Reliability
Amount of Project - $197,000
Description of Project

This project involves converting an existing 8.3kV distribution line to 27.6kV and installing step down transformers to convert 8.3kV load to the 27.6kV distribution. This project supports HCHI's strategy of eliminating 8.3kV stations and eliminating sub-transmission charges from HONI.

Business Value	Comments
Reliability/Performance	Innophos is one of HCHI's largest customers. Their manufacturing processes require a reliable supply of electricity so that unscheduled restart costs can be avoided. The current supply to Innophos is from the 31M2 circuit which is HONI owned. This circuit extends into the Wainfleet service territory

	of HONI. This exposure beyond HCHI's border increases the frequency and duration of emergency work. This project increases reliability by decreasing the exposure. Low voltage issues in the Sherbrooke area will be rectified. The entire vicinity will have two points of supply instead of one (as it is now) increasing reliability.
Community Relations	Innophos is severely impacted financially by outages. The manufacturing processes within their plant cannot be restarted without clearing their machines of the old product. This takes time and effort from unscheduled resources.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards). The risk to HCHI staff will be improved due to increased clearances of new designs, and elimination of deteriorated plant.
Regulatory Intervention	No impact.
Environmental Stewardship	The close proximity to the Grand River watershed and an old system of canals make a transformer oil spill a sensitive issue. Eliminating old plant will decrease the risk.

Project # 4 Alder Street Conversion – Phase 1 – Civil Work - Dunnville
Type of Project Municipal
Amount of Project $300,000
Description of Project

Alder Street in the community of Dunnville is receiving major deep service replacements in 2010 as part of the County's infrastructure replacement program. This street is supplied in part via rear lot assets and the assets on the road allowance are heavily encumbered by trees. Conversions of overhead assets to underground assets are very expensive partially due to the restoration work involved with roadways, sidewalks, and customers properties. When major deep service infrastructure improvements take place it is the opportune time to install civil electrical works which avoids the restoration costs. This project involves installing civil electrical works such as pad-foundations, duct, and potentially secondary in the front lot within the road improvement area.

Business Value	Comments
Reliability/Performance	Improvements due to removal of rear lot assets and the more reliable nature of underground distribution systems (at least from a weather perspective).
Community Relations	The destruction of perfectly good civil infrastructure to install underground assets is counterproductive from a County and customer perspective. Performing work before or during civil deep service work eliminates this concern.
Safety	Responding to issues with rear lot assets is always a safety concern due to limited access for tools and equipment. Responding to heavily treed overhead lines can produce some very dangerous situations for staff and the public. Conversion to underground reduces these concerns dramatically.
Regulatory Intervention	No Impact
Environmental Stewardship	No Impact

Project # 5 Eliminate Feeds from Lythmore DS – Phase 1 - East - Oneida
Type of Project Reliability
Amount of Project $127,000
Description of Project

This area is fed from HCHI owned circuits which are supplied from the HONI Lythmore distribution station. This project involves a combination of installing step down transformers and rebuilding existing 8.3kV line to 27.6kV standards. This project supports HCHI's strategy to eliminate sub-transmission charges.

Business Value	Comments
Reliability/Performance	In past years this area has been subject to low voltage when field regulators have been taken off line for maintenance or repair. Low voltage occurs at peak loading during the summer peaks of June, July, and August. Converting the area will eliminate the need to have regulators installed in the circuit and thus will correct the low voltage.
Community Relations	Will eliminate low voltage complaints.
Safety	Low voltage complaints always require intervention by HCHI field staff. Corrective actions usually involve changing transformer taps or reconfiguring the circuits temporarily to improve voltage. Eliminating the need to take corrective action will remove the risk of an incident.

Regulatory Intervention	No Impact
Environmental Stewardship	No Impact

Project # 6 Pole Replacement Program, Various Locations
Type of Project Sustainment
Amount of Project $507,360
Description of Project

See comments under Project # 2 in 2009.

2010 Other Projects

Betterments and Line Extensions

See description under 2007's discussion.

- **Account 1855 – Services**

2010 Test vs. 2009 Bridge, $196,004.

See description under 2004, 2005, and 2006 Other Projects.

Services, new and upgraded, detailed as follows:

2010 Service	Upgrade Overhead	Upgrade Underground	New	Total
<= 200 Amp, Single Phase	85,462	96,847		182,309
> 200 Amp, Single Phase	4,088	862		4,950
<= 200 Amp, Three Phase		469		469
> 200 Amp, Three Phase	268	666		934
New - Miscellaneous			7,342	7,342
Total Services	89,818	98,844	7,342	196,004

- **Account 1860 – Meters**

2010 Test vs. 2009 Bridge, $87,763

The table below represents HCHI's projected capital spending for new meters for new services, single phase and three phase that are not part of the smart meter deployment (G/S 50 kW to 150 kW). The Ontario Government's mandate for AMI is all Residential and General Service <50 kW customers. Approximately 90 accounts are 50 kW to 150 kW. As these meters are due for reverification or close to it, they will be changed to a meter that uses the AMI communications network to eliminate meter reading costs for so few accounts.

Meters detailed as follows:

2010	Single Phase Metering	Three Phase Metering	Spare Meter Capital
Meter Services	25,983	61,780	No Change
Total Meter Projects	87,763		

- **Account 1925 – Computer Equipment - Software**

2010 Test vs. 2009 Bridge, $429,068.

Capital investment continues for the ongoing development of the ESRI Distribution mapping system in 2010. Also, capital spending has been targeted for software in order to maintain current licensing requirements and to provide the necessary software applications to complete day to day work in a cost effective manner. This includes an Asset Management Software System for the retention of inspection, maintenance, and asset attribute data.

Investments in 2010 as follows:

- Continuation of HCHI's mapping work as in past years - $187,825

- Purchase of a software interface to connect the ESRI GIS mapping system with the new customer information system, NorthStar - $34,000
- Purchase an Asset Management Software System that will integrate with our current systems, NorthStar CIS, Great Plains financial, and ESRI GIS Mapping. This will provide integrated utility solutions for enhanced planning and project selection - $198,000

No other Projects for 2010 exceeded the materiality threshold.

- **Account 1930 – Transportation Equipment**

2010 Test vs. 2009 Bridge, $273,600.

As discussed in the 2009 variance analysis, an evaluation matrix is used to assist with prioritizing the order of truck replacements.

Investments in 2010 include the following:

- Replacement of a Radial Boom Derrick (RBD) truck – Chassis ordered and delivered in 2009. The body and RBD device to be installed in 2010 – $178,200
- Replacement of a bucket truck, 1995 Single Bucket Versalift MH Ford, with 239,190 km with maintenance and repairs exceeding the book value. Purchase of a 2011 Single Bucket Light Duty, Material Handling Aerial Device, over a two year period – 2010 will be the chassis only - $95,400

- **Account 1995 – Contributions and Grants - Credit**

2010 Test vs. 2009 Bridge, $(131,600).

Contributing factors to HCHI's capital contributions are line extensions for new services, contributions from developers for subdivision development, and contributions required from existing customer upgrades as per HCHI's Conditions of Service. Two evaluations

were projected to be completed for subdivisions in 2009 with 84 lots rebated. In 2010, there is only one evaluation projected to be completed for subdivisions with 28 lots. This difference in developer projected rebates of $83,800 (a net charge to contributed capital) is the primary reason for the variance increase from the 2009 bridge year to the 2010 test year.

Contributed Capital – Asset Type	New Service / Line Extension	Subdivision	Total
Poles / Towers / Fixtures	(26,426)		(26,426)
Overhead Conductors and Devices	(3,639)		(3,639)
Underground Conduit	(11,292)		(11,292)
Underground Conductors and Devices	(20,585)	(11,964)	(32,549)
Line Transformers	(20,927)	(1,000)	(21,927)
Services	(30,350)		(30,350)
Meters	(5,417)		(5,417)
Total Capital Contributions	(118,636)	(12,964)	(131,600)

Table 11
Accumulated Amortization

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Bridge ($)	Variance from 2008 Actual	2010 Test ($)	Variance from 2009 Bridge
Land and Buildings											
1805-Land											
1806-Land Rights											
1808-Buildings and Fixtures											
1905-Land											
1906-Land Rights	82,946	135,455	52,509	156,175	20,721	176,952	20,777	194,727	17,775	212,502	17,775
1810-Leasehold Improvements											
Sub-Total-Land and Buildings	82,946	135,455	52,509	156,175	20,721	176,952	20,777	194,727	17,775	212,502	17,775
TS Primary Above 50											
1815-Transformer Station Equipment - Normally Primary above 50 kV											
Sub-Total-TS Primary Above 50											
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	127,691	180,549	52,858	197,352	16,803	211,925	14,573	232,918	20,993	253,911	20,994
Sub-Total-DS	127,691	180,549	52,858	197,352	16,803	211,925	14,573	232,918	20,993	253,911	20,994
Poles and Wires											
1830-Poles, Towers and Fixtures	2,674,557	4,482,621	1,808,064	5,181,439	698,817	5,924,112	742,673	6,717,138	793,026	7,539,220	822,082
1835-Overhead Conductors and Devices	913,865	1,639,342	725,477	1,941,588	302,246	2,285,586	343,998	2,701,339	415,753	3,140,010	438,670
1840-Underground Conduit	16,431	39,507	23,076	49,690	10,184	63,472	13,782	87,407	23,935	125,939	38,532
1845-Underground Conductors and Devices	1,062,713	1,813,424	750,711	2,101,006	287,581	2,401,999	300,994	2,708,694	306,695	3,023,969	315,275
Sub-Total-Poles and Wires	4,667,566	7,974,894	3,307,328	9,273,722	1,298,828	10,675,170	1,401,447	12,214,579	1,539,409	13,829,138	1,614,559
Line Transformers											
1850-Line Transformers	1,270,175	2,202,791	932,616	2,572,465	369,674	2,921,665	349,200	3,351,731	430,066	3,802,412	450,681
Sub-Total-Line Transformers	1,270,175	2,202,791	932,616	2,572,465	369,674	2,921,665	349,200	3,351,731	430,066	3,802,412	450,681
Services and Meters											
1855-Services	124,849	284,554	159,705	361,405	76,851	445,293	83,887	538,582	93,289	639,711	101,129
1860-Meters	373,201	640,325	267,124	745,353	105,028	850,198	104,845	960,978	110,780	1,075,269	114,290
Sub-Total-Services and Meters	498,050	924,879	426,829	1,106,759	181,879	1,295,491	188,733	1,499,560	204,069	1,714,980	215,419
General Plant											
1908-Buildings and Fixtures	98,974	181,661	82,687	223,064	41,403	270,056	46,992	318,071	48,015	366,086	48,015
1910-Leasehold Improvements											
Sub-Total-General Plant	98,974	181,661	82,687	223,064	41,403	270,056	46,992	318,071	48,015	366,086	48,015
IT Assets											
1920-Computer Equipment - Hardware	138,423	285,238	146,815	311,732	26,493	361,839	50,107	427,821	65,982	478,620	50,799
1921-Computer Equipment											
1921-Computer Equipment - Hardware post March 22, 2005											
1925-Computer Software	159,400	433,553	274,153	603,454	169,901	805,120	201,666	1,155,006	349,886	1,543,784	388,778
Sub-Total-IT Assets	297,823	718,791	420,968	915,186	196,395	1,166,959	251,773	1,582,827	415,868	2,022,404	439,578
Equipment											
1915-Office Furniture and Equipment	60,977	115,420	54,443	139,324	23,904	142,611	3,287	175,453	32,842	206,213	30,760
1930-Transportation Equipment	415,059	670,358	255,299	777,195	106,837	841,028	63,833	1,022,873	181,845	1,200,243	177,370
1935-Stores Equipment											
1940-Tools, Shop and Garage Equipment	91,010	170,114	79,104	206,071	35,957	249,235	43,164	278,135	28,900	307,222	29,086
1945-Measurement and Testing Equipment											
1950-Power Operated Equipment											
1955-Communication Equipment	29,272	55,860	26,588	61,337	5,477	65,202	3,865	66,282	1,080	66,282	
1960-Miscellaneous Equipment											
Sub-Total-Equipment	596,318	1,011,752	415,434	1,183,927	172,175	1,298,076	114,149	1,542,743	244,667	1,779,960	237,217
Other Distribution Assets											
1825-Storage Battery Equipment											
1970-Load Management Controls - Customer Premises											
1975-Load Management Controls - Utility Premises											
1980-System Supervisory Equipment											
1985-Sentinel Lighting Rental Units											
1990-Other Tangible Property											
1995-Contributions and Grants - Credit		(241,907)	(241,907)	(326,089)	(84,182)	(427,196)	(101,107)	(534,082)	(106,886)	(646,232)	(112,150)
1996-Hydro One S/S Contribution											
Sub-Total-Other Distribution Assets		(241,907)	(241,907)	(326,089)	(84,182)	(427,196)	(101,107)	(534,082)	(106,886)	(646,232)	(112,150)
ACCUMULATED AMORTIZATION TOTAL	7,639,543	13,088,866	5,449,323	15,302,560	2,213,695	17,589,099	2,286,538	20,403,075	2,813,976	23,335,161	2,932,087

VARIANCE ANALYSIS ON ACCUMULATED AMORTIZATION

Changes in accumulated amortization are directly affected by changes in fixed assets due to additions, the removal of fully amortized assets from the grouped asset classes, and the disposition of identifiable assets. The 2006 Board Approved closing balance for accumulated amortization is based on HCHI's 2004 year end account balances, plus Tier 1 capital adjustments approved in HCHI's 2006 EDR Application. As such, the variance between 2006 Board Approved and 2006 Actual represents two years of amortization changes, and in order to arrive at the annual impact, the variance must be divided by two.

From 2006 Actual to the 2010 Test Year Table 11 shows that the change in accumulated amortization, which is a representation of the amortization expense in the year for each of the above accounts, has not changed materially from year to year. The change in accumulated amortization is a result of capital expenditures over a four year period. Since a detailed analysis of capital expenditures has been provided in this Exhibit, no further explanation of the changes in accumulated amortization accounts is required. The variance analysis detailed in Exhibit 4, Tab 2, Schedule 3 for "Amortization Expense" also provides support for the variances in "Accumulated Amortization" in Table 11 of this Exhibit.

ASSET MANAGEMENT PLAN SUMMARY:

HCHI is an infrastructure-based business with its distribution system assets being the key element in the delivery of electricity to its existing and new customers.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, sustainment and retirement; in other words, the management of the asset through its entire life cycle. The goal is to strategically define how the assets are to be managed with the expectation to optimize the whole life business impact of costs, performance and risk exposures. Once the strategy is defined then the detailed processes used to manage the asset can be defined. Key inputs and support processes used to create HCHI's Distribution Asset Management Plan (DAMP) are as follows:

- HCHI's – Distribution System Maintenance and Inspection Program (included as Appendix C in the DAMP)
- Distribution Asset Condition Assessment report prepared by Kinectrics Inc. (included as Appendix G in the DAMP)
- Discretionary Capital Projects Prioritization Model report prepared by Kinectrics Inc. (included as Appendix M in the DAMP)
- Reliability Indices
- Other Reliability Information –Outage Causes, Components, etc.

The DAMP was created in 2009 as a supporting document to HCHI's 2010 Rate Application and to provide the framework for future asset life cycle management. It is very much a work in progress and will evolve with time. Where appropriate and within

the DAMP gaps are noted for future development. Accordingly, the DAMP is a "Draft" document yet to be approved by HCHI's Board of Directors.

HCHI's DAMP is attached as Appendix A and covers all distribution assets except meters. There is no requirement for a short-term strategy to replace meters as the Smart Meter Initiative will result in the replacement of most meter assets in the next few months. The Smart Meter installation project is scheduled to be completed by the end of December 2009.

CAPITALIZATION POLICY:

HCHI's Capitalization Policy is as follows:

1. Definition of an Asset

CICA Handbook paragraph 1000.29 defines assets as economic resources controlled by an entity as a result of past transactions or events from which future economic benefits may be obtained. Assets have three essential characteristics:

1. They embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows and in the case of not-for-profit organizations, to provide services.

2. The entity can control access to the benefit.

3. The transaction or event giving rise to the entity's right to, or control of, the benefit has already incurred.

In addition, in identifying a benefit there must be:

A. An ability to earn income or supply a service.

B. A reasonable expectation that the benefit will be provided in future periods.

C. The future period must be identifiable and greater than one year.

The CICA Handbook specifically defines a capital asset as identifiable assets comprising property, plant and equipment and intangible properties that meet all of the following criteria:

1. Are held for use in the production of supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair to other capital assets.

2. Have been acquired, constructed or developed with the intention of being used on a continuing basis.

3. Are not intended for sale in the ordinary course of business.

In regard to whether to capitalize intangible property costs, the CICA Handbook states that a degree of certainty as to future benefits to be derived from costs attributed to developing intangible properties varies and in many cases, the expected future benefits may be too uncertain to justify asset recognition. However, when future benefits are reasonably assured, such costs should be capitalized (subject to materiality considerations) (CICA s 3062.07).

2. Capitalizing Upgrades and Improvements – "Betterments"

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 physical output or service capacity,
- associated operating costs are lowered,
- the life or useful life is extended, or
- the quality of output is improved.

The definition of betterment is more difficult to apply to tangible capital assets that are complex networks of systems and are very long-lived, such as water systems because identifying expenditures that extend their lives may not be practicable.

For complex network systems the following distinctions can be used to identify maintenance and betterments:

1. Maintenance and repairs maintain the predetermined service potential of a tangible capital asset for a given useful life. Such expenditures are expenses in the period in which they are made.

    a. *A repair or replacement is comprised of the repair of an existing component, or the replacement of an existing component with a similar component.*

Betterments increase service potential (and may or may not increase the useful life of a tangible capital asset). Such expenditures would be included in the cost of the related asset.

3. Capitalization Threshold

Theoretically, any item that meets the definition and recognition criteria would be recorded as a tangible capital asset (TCA). In practical terms, departments shall treat any asset as a capital asset that in addition to the above conditions has a useful life in excess of one year and a per item cost greater than $500. This threshold may be changed at the discretion of Management and on an item-by-item basis if a department wishes to capitalize an amount lower than the amount prescribed above in order to ensure all material capital assets are included in the financial statements. Assets below the threshold are expensed in the period of purchase.

Land will always be capitalized, regardless of cost.

Characteristics to Consider

Repairs = Expense	Betterments = Capital Assets
All items – life less than 1 year	Life of more than 1 year
All items under $500	Items greater than $500
Replacement of individual components of a TCA due to age, "wear-and-tear" and damage in order to maintain the TCA in an operating condition without significantly enhancing functionality, capacity, usability and efficiency	Replacement of motor and parts that prolong the useful life
Renovations – carpeting, painting, etc.	The estimated life of the asset is extended by more than 25%
System and equipment repairs, in cases where the service potential of a building isn't enhanced, repairs – boilers, elevators, control system, etc.	The cost results in an increase in the capacity of the asset
Building repairs that are required in the normal maintenance process	The efficiency of the asset is increased by more than 10%
Repairs to restore assets damaged by fire, flood or similar events, to a condition just prior to the event	Significantly changes the character of the asset
	Reduction in operating cost

WORKING CAPITAL CALCULATION

Overview

HCHI's working capital allowance is forecast to be $5,457,502 for 2010 and is based on the "15% of specific OM&A accounts formula approach" referred to at page 8 of the Board's Updated Filing Requirements, May 27, 2009. HCHI has provided its calculations by account for each of 2006 Actual, 2007 Actual, 2008 Actual, the 2009 Bridge Year and the 2010 Test Year in Table 12 on the following pages.

The accounts included in the calculation are eligible distribution expenses (operation, maintenance, billing and collecting, community relations, administrative and general expenses and property taxes) and power supply expenses.

For power supply expenses in the 2009 bridge year, HCHI has assumed a cost of power of $0.06030 per kWh for January to April and $0.06072 per kWh for May to December based on the OEB RPP Report dated October 15, 2008 and April 15, 2009 respectively. For power supply expenses in the 2010 test year, HCHI has assumed a cost of power of $0.06072 per kWh for the entire year based on the OEB RPP Report dated April 15, 2009. These prices, as well as the approved rates for the other components of power supply expenses (network, connection, and wholesale market services) were multiplied by the weather normalized energy volumes as identified in Exhibit 3 Tab 2 Schedule 2 Table 10 to obtain the total power supply expenses. It should be noted that HCHI calculated the network and connection components of the power supply expenses based on approved rates from both HONI and the IESO. This is due to the fact that HONI is the Retail Transmission customer to the IESO at some feeders within HCHI's service territory as discussed in Exhibit 1 Tab 1 Schedule 12.

Table 12
Working Capital Calculation by Account

Expense Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Actual	Allowance for Working Capital	2009 Bridge	Allowance for Working Capital	2010 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%		15%
Operation										
5005-Operation Supervision and Engineering	326,519	48,978	349,362	52,404	431,555	64,733	492,414	73,862	499,249	74,887
5016-Distribution Station Equipment - Operation Labour	11,195	1,679	17,379	2,607	22,329	3,349	17,334	2,600	17,889	2,683
5017-Distribution Station Equipment - Operation Supplies and Expenses	14,930	2,240	15,438	2,316	16,966	2,545	19,000	2,850	19,570	2,936
5020-Overhead Distribution Lines and Feeders - Operation Labour	113,403	17,010	120,354	18,053	107,617	16,143	115,403	17,310	120,005	18,001
5035-Overhead Distribution Transformers- Operation	260,648	39,097	274,858	41,229	186,097	27,915	212,380	31,857	221,961	33,294
5040-Underground Distribution Lines and Feeders - Operation Labour	39,801	5,970	47,651	7,148	64,878	9,732	57,554	8,633	58,608	8,791
5055-Underground Distribution Transformers - Operation	17,542	2,631	11,516	1,727	-1,528	-229	15,186	2,278	15,696	2,354
5065-Meter Expense	164,296	24,644	200,949	30,142	234,187	35,128	257,227	38,584	276,493	41,474
5070-Customer Premises - Operation Labour	6,149	922	7,778	1,167	5,995	899	13,127	1,969	15,294	2,294
5085-Miscellaneous Distribution Expense	204,419	30,663	147,906	22,186	153,967	23,095	186,655	27,998	192,883	28,932
Sub-Total	**1,158,902**	**173,835**	**1,193,191**	**178,979**	**1,222,063**	**183,309**	**1,386,280**	**207,942**	**1,437,648**	**215,647**
Maintenance										
5105-Maintenance Supervision and Engineering	81,122	12,168	98,399	14,760	117,796	17,669	125,994	18,899	129,706	19,456
5114-Maintenance of Distribution Station Equipment	67,382	10,107	204,963	30,744	215,629	32,344	90,167	13,525	107,029	16,054
5120-Maintenance of Poles, Towers and Fixtures	298,799	44,820	763,957	114,594	641,332	96,200	637,848	95,677	607,398	91,110
5125-Maintenance of Overhead Conductors and Devices	425,852	63,878	767,659	115,149	670,371	100,556	848,105	127,216	900,963	135,144
5130-Maintenance of Overhead Services	133,061	19,959	144,538	21,681	129,686	19,453	151,442	22,716	158,103	23,715
5135-Overhead Distribution Lines and Feeders - Right of Way	227,225	34,084	613,536	92,030	548,666	82,300	564,461	84,669	556,518	83,478
5145-Maintenance of Underground Conduit	933	140	1,587	238	13,225	1,984	9,574	1,436	10,687	1,603
5150-Maintenance of Underground Conductors and Devices	39,713	5,957	16,730	2,510	19,345	2,902	37,325	5,599	33,209	4,981
5155-Maintenance of Underground Services	93,030	13,955	72,582	10,887	127,255	19,088	108,412	16,262	111,495	16,724
5160-Maintenance of Line Transformers	48,373	7,256	151,686	22,753	161,601	24,240	166,502	24,975	159,370	23,906
5175-Maintenance of Meters	13,623	2,043	19,118	2,868	10,295	1,544	25,366	3,805	26,272	3,941
5195-Maintenance of Other Installations on Customer Premises	1,683	252	1,663	249	5,201	780	2,048	307	1,983	297
Sub-Total	**1,430,796**	**214,619**	**2,856,418**	**428,463**	**2,660,402**	**399,060**	**2,767,244**	**415,087**	**2,802,733**	**420,410**

Expense Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Actual	Allowance for Working Capital	2009 Bridge	Allowance for Working Capital	2010 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%		15%
Billing and Collections										
5305-Supervision	121,433	18,215	128,749	19,312	134,389	20,158	142,969	21,445	144,980	21,747
5310-Meter Reading Expense	332,761	49,914	293,130	43,970	279,893	41,984	280,668	42,100	296,609	44,491
5315-Customer Billing	486,043	72,906	511,791	76,769	536,957	80,544	580,156	87,023	602,980	90,447
5320-Collecting	153,215	22,982	228,735	34,310	226,491	33,974	250,781	37,617	254,886	38,233
5325-Collecting- Cash Over and Short	1,001	150	-135	-20	-7	-1	0	0	0	0
5335-Bad Debt Expense	98,537	14,781	57,092	8,564	84,437	12,666	30,000	4,500	30,000	4,500
5340-Miscellaneous Customer Accounts Expenses	53,231	7,985	59,293	8,894	41,819	6,273	70,761	10,614	73,968	11,095
Sub-Total	**1,246,221**	**186,933**	**1,278,655**	**191,798**	**1,303,979**	**195,597**	**1,355,335**	**203,300**	**1,403,423**	**210,513**
Community Relations										
5410-Community Relations - Sundry	35,158	5,274	32,834	4,925	26,110	3,917	27,972	4,196	28,836	4,325
5415-Energy Conservation	50,773	7,616	91,012	13,652	12,609	1,891	18,000	2,700	18,000	2,700
Sub-Total	**85,931**	**12,890**	**123,846**	**18,577**	**38,719**	**5,808**	**45,972**	**6,896**	**46,836**	**7,025**
Administrative and General Expenses										
5605-Executive Salaries and Expenses	71,032	10,655	76,167	11,425	67,824	10,174	71,428	10,714	71,428	10,714
5610-Management Salaries and Expenses	544,469	81,670	585,101	87,765	621,393	93,209	638,854	95,828	654,364	98,155
5615-General Administrative Salaries and Expenses	320,631	48,095	440,996	66,149	482,068	72,310	524,809	78,721	542,981	81,447
5620-Office Supplies and Expenses	93,198	13,980	101,010	15,152	110,866	16,630	106,564	15,985	112,380	16,857
5630-Outside Services Employed	339,990	50,999	285,968	42,895	362,541	54,381	385,077	57,762	402,106	60,316
5635-Property Insurance	16,702	2,505	14,912	2,237	18,069	2,710	18,844	2,827	19,408	2,911
5655-Regulatory Expenses	86,882	13,032	79,392	11,909	89,252	13,388	87,070	13,061	101,208	15,181
5665-Miscellaneous General Expenses	133,952	20,093	74,166	11,125	59,756	8,963	57,355	8,603	57,455	8,618
Sub-Total	**1,606,856**	**241,028**	**1,657,712**	**248,657**	**1,811,769**	**271,765**	**1,890,001**	**283,500**	**1,961,330**	**294,199**
Taxes Other Than Income Taxes										
6105-Property Taxes	51,609	7,741	52,111	7,817	51,523	7,728	51,937	7,791	53,447	8,017
Sub-Total	**51,609**	**7,741**	**52,111**	**7,817**	**51,523**	**7,728**	**51,937**	**7,791**	**53,447**	**8,017**
Cost of Power										
4705-Power Purchased	21,718,656	3,257,798	21,643,575	3,246,536	20,893,260	3,133,989	22,183,673	3,327,551	22,363,781	3,354,567
4708-Charges WMS	2,369,835	355,475	2,360,929	354,139	2,306,243	345,936	2,326,495	348,974	2,373,264	355,990
4714-Charges NW	2,352,389	352,858	2,259,050	338,858	1,937,461	290,619	1,790,955	268,643	1,955,675	293,351
4716-Charges CN	2,034,016	305,102	1,933,331	290,000	1,809,389	271,408	1,682,412	252,362	1,775,798	266,370
4750-Charges LV	214,285	32,143	319,595	47,939	309,753	46,463	301,683	45,252	209,412	31,412
Sub-Total	**28,689,182**	**4,303,377**	**28,516,480**	**4,277,472**	**27,256,106**	**4,088,416**	**28,285,218**	**4,242,783**	**28,677,930**	**4,301,690**
WORKING CAPITAL ALLOWANCE TOTAL	**34,269,497**	**5,140,425**	**35,678,413**	**5,351,762**	**34,344,561**	**5,151,684**	**35,781,987**	**5,367,298**	**36,383,347**	**5,457,502**

HALDIMAND COUNTY HYDRO INC.

Distribution Asset Management Plan
2009 – 2028

DRAFT

Haldimand County Hydro Inc.
Distribution Asset Management Plan
2009 – 2028
August 2009

HALDIMAND COUNTY HYDRO INC.
Distribution Asset Management Plan
2009 – 2028

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FORWARD

This document is the first attempt by Haldimand County Hydro Inc. (HCHI) to put its asset management strategy into words. HCHI and its predecessors have been managing the distribution system assets since electrification occurred in the province of Ontario. Although the concept of asset management is not new, the formal documentation of a plan is new for this utility. The "Distribution Asset Management Plan" (DAMP) provides stakeholders an explanation of the framework within which HCHI intends to operate and manage the distribution system assets to meet the required service levels while maintaining a safe and reliable distribution system for its consumers.

Kinectrics Inc. was engaged to prepare a Distribution Asset Condition Assessment and this report dated March 10, 2009 concludes "Generally, HCHI's assets are in "Good" condition based on the available information, expert opinion and one-day field observations". This assessment is used as a tool in planning future sustainment projects. Notwithstanding the generally good condition of the distribution system as a whole, many assets have either reached the end of life or have developed defects which require their early retirement.

HCHI is also planning for developmental projects during the life of this plan which will require significant investment. In order to support the justification for developmental projects Kinectrics Inc. was engaged to help establish a ""Discretionary" Capital Projects Prioritization Model". This model is described in Kinectrics report dated March 16, 2009 and the methodology is used to describe discretionary projects that are part of this DAMP.

This investment in both sustainment and discretionary projects must be approved by the Ontario Energy Board (OEB) through the rate application process.

HCHI welcomes feedback from stakeholders on its DAMP and its approach to maintaining a cost effective, safe, and reliable electrical supply to Haldimand County.

Doug Curtiss, P.Eng.
Operations Manager
Haldimand County Hydro Inc.

Liability Disclaimer

The information and statements made in this DAMP are prepared on the assumptions, projections, and forecasts made by Haldimand County Hydro Inc. and represents HCHI's intentions and opinions at the date of preparation.

Circumstances will change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and HCHI may, at a later date, decide to take different actions from those it currently intends to take as expressed in this DAMP.

HCHI cannot be held liable for any loss, injury, or damage arising directly or indirectly as a result of use or reliance on any information contained within this DAMP.

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1 SUMMARY

1.1 The Purpose of the Plan

The purpose of this Distribution Asset Management Plan (DAMP) is to outline how Haldimand County Hydro Inc. (HCHI) will develop, manage, and maintain its distribution system equipment to provide a safe, reliable, efficient, and cost effective distribution system.

The DAMP identifies the major initiatives and projects to be undertaken over the planning period to meet customer and stakeholder requirements. Preparation of the DAMP in this format is intended to supplement HCHI's rate application in August 2009 to the Ontario Energy Board (OEB).

1.2 Period Covered

The planning horizon of the DAMP is from 2009 to 2028. It is intended that the DAMP will be reviewed on a periodic basis.

The planning horizon extends for a twenty (20) year period. This period was selected to match Thunder Bay Hydro's benchmark, which was disclosed in an Electrical Distributors Association (EDA) Operations Council Forum on May 9, 2008 – "Asset Management for LDC's Getting the Plan Right from Conception to Completion". However, the main focus of the plan concentrates on the period from 2009 to 2013 a five (5) year period. This five year period matches with the five (5) year forecast. Specific project plans with good detail are available for 2009 and 2010. For the years 2011 to 2013 the detail is preliminary only. Beyond this time, analysis tends to be more trend related and based on past history. The Asset Condition Assessment is based on a planning horizon of twenty (20) years and predicts the sustainment of asset through to 2028.

It is very likely that new developments, that are not identified here, will arise at any given time even in the short term of five (5) years.

1.3 Key Assumptions

The development of this DAMP is based on a series of key assumptions that are made as a foundation for planning and forecasting predictions of future activities, whether to maintain, replace or develop new assets (discretionary capital projects).

The key assumptions for this DAMP are as follows:

a) Electricity growth rates will continue to be slow in the next five (5) years due to a sluggish economy and the impact of the Conservation and Demand Management (CDM) Programs in lowering demand and electricity usage.
b) Recognition that the economy of Haldimand County depends on a secure and reliable supply of electricity.
c) In the next five (5) years regulatory activities by the Ontario Energy Board (OEB) will continue at the current pace putting a heavy strain on HCHI's resources. Beyond this timeframe it is hoped that some stability with regulatory requirements will consume less resources.

d) The Green Energy Act which received Royal Assent on May 15, 2009 will require significant investment in the distribution infrastructure in order to meet the "Smart Grid" characteristics alluded to in the legislation.
e) The installation of smart meters in 2009 will require significant investment to harness the capability of the new metering devices and to promote the "Smart Grid".
f) With reference to the "Smart Grid" new technologies will be developed within the planning horizon of this plan. However, at this time the specific nature of how these new technologies would be developed to benefit HCHI's customers is not known.
g) Present service levels will continue to be maintained and will remain a balance between customer needs, price-quality tradeoffs, and industry best practice(s). Service levels will not be changed significantly due to introduction of new regulatory requirements.
h) HCHI's DAMP is a strategic document to convey future distribution system development and maintenance plans to stakeholders.
i) HCHI's asset management systems will continue to be developed in order to process performance information to meet demand, capacity, security, and reliability levels in a timely manner.
j) Use of outside line construction firms to perform distribution maintenance, replace, and install assets (as prescribed by work plans of discretionary projects) will continue.
k) Compliance with relevant regulatory requirements as they pertain to electricity rates, filing requirements, health & safety, and environmental protection will be maintained.
l) Meet the requirements of our Shareholder by achieving the objectives set down in HCUI's mission statement.
m) Asset management planning involves forecasts based on information collected from many sources. Distribution system development for the next two (2) years (2009/10) has been established. The following three (3) years (2011 thru 2013) are less certain and the remaining years of the plan are based solely on trending. As the years pass a regular review of this plan will ensure it is the best it can be.

Review of future achievement (apart from regulatory compliance) will be centred on the following areas:

a) Health & Safety Performance
b) Financial Performance
c) Economic Efficiency Performance
d) Reliability Consistency and Improvement
e) Environmental Performance

1.4 Asset Management Systems

Asset management systems used by HCHI include inspection and maintenance databases, paper records of inspection and maintenance activities, reliability database, asset attribute databases, a graphics information system (GIS – ESRI Platform), and a load flow analysis program (CYME Software).

HCHI's strategy with respect to asset management is to build the information system for assets around the ESRI GIS platform. Connectivity to other systems such as the Customer Information System (CIS – Harris Platform), and databases enhance the sophistication of the entire asset management product. The GIS platform was initiated in 2004 and is fully functional with land base representation, circuit representation, asset location, and connectivity to asset records, inspection data records, and maintenance activity. Currently HCHI is collecting GPS coordinates for pole locations and anticipates having all poles identified by the end of 2010.

The CYME software was purchased in 2008 and is not yet in operational mode. HCHI does not have a SCADA system.

1.5 Distribution System & Asset Description

The HCHI distribution system supplies 20,815 customers throughout the Municipality of Haldimand County. These customers are supplied by three (3) Hydro One owned transformer stations (TS's) which deliver 352.2GWh of billed energy at a maximum demand of 88.2MW. (Figures from 2008).

The service area of HCHI covers 1252 square kilometers, and includes all geography within the borders of the municipality of Haldimand County. Of the 1252 square kilometers – 36 square kilometers is urban and 1,216 is rural.

A breakdown of the assets in terms of their original cost is shown in Appendix A and a map of the service territory shown in Appendix B.

1.6 Service Levels

HCHI abides by the OEB prescribed levels of service and reliability standards dictated by the following:

- Chapter 15 of the 2006 Electricity Distribution Rate Handbook – Service Quality Regulation and,
- Amendments to the Distribution System Code - Board File No. EB-2008-0001.

There have been no customer surveys initiated to ascertain what HCHI's customer's feel about the service it provides and if reliability expectations are being met.

1.7 Network Development Plans

Asset enhancement and development projects have been identified and details are outlined in the capital budgets for 2009 and 2010. Trended capital budgets have been prepared for years 2011 thru 2013.

1.8 Life Cycle Asset Management

Information about HCHI's asset attributes and condition data are held within databases, various paper records and files. Asset conditions are assessed by various inspection and maintenance activities. These activities are analyzed to determine what appropriate maintenance intervals best suit the asset. Detailed attribute condition information is presently being collected and with time the confidence level of this information will improve.

A comprehensive Distribution System Maintenance and Inspection Program (attached as Appendix C) has been developed to guide HCHI's decisions with respect to maintenance & inspection intervals.

In 2008 HCHI initiated an Asset Condition Assessment (ACA) (attached as Appendix G) with a well known consulting firm Kinectrics. The results of this ACA contribute to the decision making process when plans are made to replace or maintain an asset.

Operational and maintenance expenditures are outlined in the O&M budgets for 2009 and 2010.

1.9 Risk Management

HCHI's Distribution System Maintenance and Inspection Program document is aimed in part to protect the public from physical, electrical, and environmental hazards by maintaining a schedule of regular asset inspections or maintenance activities.

Ontario Regulation 22/04 - Electrical Distribution Safety is a key regulation which requires HCHI and all other LDCs to maintain distribution standards, material standards, and construction verification programs to safeguard the public from hazards associated with the distribution system. The Electrical Safety Authority (ESA) is responsible for enforcing the regulation and this is done through a system of annual audits and regular field inspections.

HCHI promotes excellence in health and safety management in order to prevent losses to people, assets, environment, and reputation. Keys to this H&S Management system are the evaluation of risk for all workplace hazards, regular H&S meetings with staff, and feedback on losses or near losses occurring in the workplace.

Written emergency response procedures have been prepared as follows:

a) Distribution System Emergency Contingency Plan
b) Spill Response Measures
c) Spill Response Measures & Transport Procedures for PCB Contaminated Equipment

HCHI will follow all regulatory requirements and guidelines to ensure the distribution system has a low risk impact on the environment.

1.10 Evaluation of Performance

Formal performance benchmarks have not been established at HCHI. However, a number of initiatives have been undertaken to develop data systems from which performance measures can be developed. As initiatives are implemented more data is available for analysis which will lead to better information. Once a better stream of information is available specific performance indicators can be created. HCHI's philosophy is one of continuous improvement and the evaluation of performance is one area where more development activity is required.

2 Background and Objectives

2.1 Purpose of this DAMP

The purpose of the DAMP is to provide a management framework to ensure that HCHI:

a) Maintains service levels that will meet customer, community, and regulatory expectations for its distribution system network.
b) Understands what levels of distribution system capacity, reliability, and security of supply will be required both now and in the future, and what issues will drive these requirements.
c) Has programs and procedures to manage all phases of the distribution system life cycle from inception to retirement.

d) Has considered the management of the distribution system in terms of the best risk management practices with the ultimate goal of minimizing identified risks.
e) Has made adequate provisions to fund all phases of the distribution system asset life cycle.
f) Makes decisions based on structured business strategies and models.
g) Has a continuously improving knowledge of its assets with respect to locations, age, condition, capacity, and attributes.

This DAMP is not intended to be a detailed description of HCHI's distribution system assets, but it is intended to be a description of the thinking, the policies, the strategies, the plans, and the resources that HCHI uses to manage the assets.

2.2 Planning and Operating Contexts

All of HCHI's distribution system assets exist within a strategic context that is shaped by a wide range of issues including its parent company Haldimand County Utilities Inc. (HCUI), Strategic Plan (which contains HCUI's Vision, Mission, and Goals), this DAMP, regulatory environment, government policy objectives, commercial pressures, and technology trends. HCHI's distribution assets are also influenced by technical regulations (i.e. – construction and clearance standards), asset deterioration, and various risk exposures independently of the strategic context.

2.2.1 Strategic Context

HCHI's strategic context includes many issues that range from the local and Canadian economy to developing technologies. Issues which are considered to impact this DAMP include:

a) The prevailing regulatory environment which constrains electricity rates and rates of return, requires stable or improving reliability indices, and requires complex reporting of financial and operating performance.
b) Government policy objectives such as the implementation of conservation and demand management programs, smart meters and the introduction of the Green Energy Act.
c) HCHI's commercial goals.
d) Local, national, and global economic cycles, in particular the decline of the steel industry and future closure of the Nanticoke Generating Station.
e) Interest rates and the general business confidence in Haldimand County which influences the rates at which new customers connect to lines.
f) Ensuring sufficient funds and skilled people are available in the short, medium, and long term to resource HCHI's service requirements.

2.2.2 Independence from Strategic Context

While HCHI's assets and asset configuration will be shaped by the strategic issues identified above in "Strategic Context" that are relevant to its stakeholders, it is also important to recognize that the assets will also be influenced (and sometimes constrained) by issues that are independent of the strategic context. For example the rate at which wooden poles rot is independent of the scarcity of skilled contractors. This issue may constrain the rate at which HCHI replaces rotten poles, but it does not influence the rate of rot.

Samples of issues that are independent of HCHI's strategic context include:

a) Technical regulations including Regulation 22/04 – Electrical Safety and the new Regulations on Farm Stray Voltage.
b) Asset configuration, condition, and deterioration – these parameters will significantly limit the rate at which HCHI can invest in upgrades or enhancements to the distribution system.
c) The physical characteristics of electricity systems which govern such fundamental issues as voltage regulation, capacity, power flows, and faults.
d) Physical risk exposures – exposure to such events as wind, lightning, snow/ice, motor vehicle impacts, theft of copper, and unwanted human interference are independent of strategic context.
e) Health and safety requirements such as line clearances and grounding of equipment.

2.3 Key Planning Documents

2.3.1 Vision and Mission Statements

Haldimand County Utilities Inc. (HCUI) is the parent company of Haldimand County Hydro Inc. (HCHI). HCHI on its own does not have a specific strategic plan; however, for all practical purposes HCHI's strategic plan flows from that of HCUI. HCHI's vision and mission statements are therefore, as follows:

HCHI's vision is:

> **To become recognized as a leading participant in the electricity distribution and related businesses sector in Ontario known particularly for high quality service, resilience, and adaptability and continuous improvement and efficiency.**

HCHI's mission is:

> **To provide efficient, reliable, and safe electricity distribution and other related services to customers and to contribute to the development of our jurisdiction's economy and our employees and the protection of the environment while enhancing the value of Haldimand County Hydro Inc.**

2.3.2 Strategic Plan

The HCUI Strategic Plan specifies the goals required to achieve the vision and mission. For each goal the planned actions and performance measures required to measure the actions success is detailed. The DAMP is a key tool used to set the action plan for creating capital and operations/maintenance budgets over the planning horizon.

2.3.3 Asset Strategy

The asset strategy, which until now, has not been formally documented as an asset management plan, has been utilized to varying degrees since the inception of the distribution system in Ontario. The guiding principles for today's distribution system asset strategy are:

a) Maintain awareness of safety around electricity at the forefront for company, customers, and the general public.
b) Exploit the availability of lines constructed for 27.6kV to improve reliability and electrical losses.
c) As maintenance and construction occurs upgrade hardware on all distribution equipment to facilitate a seamless transition to the 27.6kV feeder voltage.
d) Design the distribution system with the intent of maximizing the reduction in electrical losses.
e) Improve customer reliability through effective maintenance plans and planned replacement of assets at their end of life.
f) Maintain power quality by implementing the modeling of the electrical distribution system in GIS and modeling software (CYME).

The implications of these guiding principles are rooted in HCHI's sustainment and discretionary projects.

2.3.4 Prevailing Regulatory Environment

The Electricity Distribution Industry in Ontario is regulated under the Ontario Energy Board Act, 1998, the Electricity Act, 1998, and the Electricity Restructuring Act, 2004 all of which are administered by the Ontario Energy Board (OEB).

The Ontario Energy Board Act, 1998 sets out the following guiding objectives for the OEB with respect to electricity:

- To protect the interests of consumers with respect to prices and the adequacy, reliability, and quality of electricity service.
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

These regulatory requirements dictate or heavily influence HCHI's rates, fees, and return on equity. Rates are required by legislation to be approved annually by the mechanisms specified by the OEB.

2.3.5 Government Policy Objectives

In May 2009 the Ontario Legislature passed Bill 150, the Green Energy and Green Economy Act, 2009. This legislation is a framework legislation aimed at making fundamental changes to the roles and responsibilities of local distribution companies (LDC's). This act will lead to a number of supporting regulations required to implement the Act. The implications of the act will likely result in significant asset expenditures by LDC's to support embedded generation and the ideals of a "smart grid". However, at this time it is too early to determine what impact this legislation will have on capital investments and subsequent rates to support these expenditures.

2.3.6 Annual Business Planning

HCHI produces, has produced by third parties, or updates a number of key documents which support the annual business planning process. These documents include the distribution system maintenance and inspection program, asset condition assessment, detailed budgets (two years forward), and a five year forecast. Going forward, this distribution asset management plan will also be reviewed.

2.3.7 Annual Budgets

Each year HCHI produces an annual budget for the year ahead which reflects the costs of individual projects and expenditures over the year. This budget is created by reviewing asset and operational issues experienced in the past and anticipated for the future. This budget contributes to the long term alignment with the strategic context. It must be understood that this alignment process is very much a moving target.

For the last two years and in support for HCHI's rate application in 2009, HCHI has produced budgets going forward two years. In addition to the detailed annual budget a five year forecast details trended costs over this period. The projects detailed in year's three to five have less detail than those in years one and two.

A critical activity for HCHI (moving forward) is to ensure that the annual budget reflects the fundamentals of this DAMP.

2.4 Period Covered by this DAMP

This DAMP covers a period from January 1, 2009 to December 31, 2028.

There is an obvious degree of uncertainty in any predictions of the future and as such the DAMP contains a level of uncertainty. The influence of government regulation, ongoing adjustments to LDC regulation by the OEB, customer growth, and the general state of the economy makes for a substantial degree of uncertainty.

Offsetting this uncertainty is the management of present assets and their current condition evidenced by the Asset Condition Assessment prepared in 2008/09. This knowledge allows for an appropriate plan to maintain a safe and reliable distribution system to meet present customer needs.

Accordingly HCHI has established the following certainties to the timeframes of the DAMP:

Timeframe	Residential	Commercial/Industrial	Embedded Generation
Year 1	Certain	Little if any certainty	Some certainty
Year 2	Certain	Little if any certainty	Some certainty
Year 3 to 5	Some Certainty	Little if any certainty	Little if any certainty
Year 6 to 20	Little if any certainty	Little if any certainty	Little if any certainty

2.5 Managing Stakeholder Interests

2.5.1 Identifying Stakeholders

HCHI is owned by HCUI whose sole shareholder is The Corporation of Haldimand County. Other stakeholders include:

a) Electricity retailers, customers, and end consumers
b) Contractors and service providers
c) Distribution Supplier - Hydro One
d) Tree owners
e) Government agencies such as the OEB, OPA, & IESO
f) Land owners where HCHI lines run

HCHI has contact with all of its stakeholders. Their suggestions provide opportunities for HCHI to conduct its business and provide perspective about rates and service levels.

2.5.2 Accommodating Stakeholder Interests

Stakeholder interests can be viewed from a number of perspectives including financial stability, electricity rates, quality of supply, safety, and compliance. Financial stability is required to ensure that shareholders and lending institutions have sufficient confidence to continue owning and investing in HCHI. Electricity rates provide the means for HCHI to create revenue and signal underlying costs. Not charging appropriate rates has economic implications for both HCHI and its customers. Quality of Supply includes emphasis on reliability with respect to the number of interruptions, the duration of interruptions, the amount of flicker, and the quality of voltage. Safety involves staff, contractors, customers, and the general public. HCHI must ensure the operation of the distribution system is safe for all. Compliance with respect to financial, safety, and environmental matters need to be complied with.

HCHI accommodates stakeholder interests as follows:

Interest	How HCHI accommodates stakeholder interests
Financial Stability	HCHI will accommodate stakeholders' needs for long term viability by returning a dividend to the shareholder.
Electricity Rates	HCHI's revenue is constrained by regulatory requirements, conservation and demand management activities, and the state of the economy. Failure to collect enough revenue to fund reliable assets will impact customers in a negative way. Conversely collecting too much revenue penalizes customers and transfers a disproportionate proportion of wealth to the shareholder. HCHI's pricing strategy must be cost effective and at the same time be enough to continue to balance distribution system security, capacity, reliability, and return on investment.
Quality of Supply	Although no customer surveys have taken place, our experience would indicate that customers in general place a great emphasis on lessening the duration and frequencies of interruptions. For this reason HCHI will continue to effectively rebuild its infrastructure with funds available.
Safety	HCHI will ensure that the public is kept safe by ensuring all assets are structurally sound, live conductors have maintained at least minimum clearances, enclosures are kept locked, and touch & step potentials are kept to a minimum. HCHI will ensure the safety of its staff by implementing and continuously improving its safety management program.
Compliance	HCHI will disclose performance information as required by regulators and ensure that safety issues are thoroughly documented.

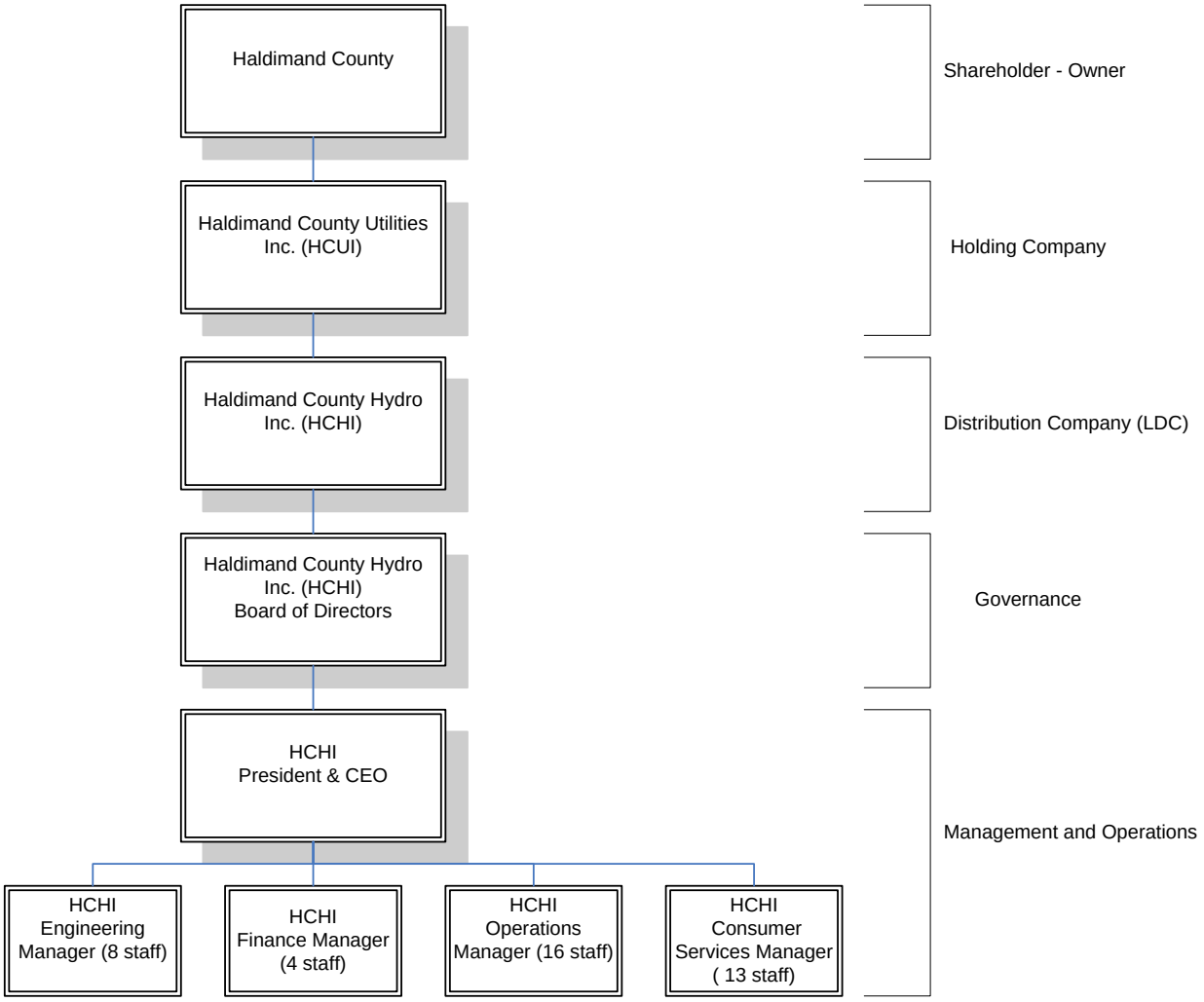
2.5.3 Managing Conflicting Interests

Conflicting interests will be managed as follows:

- Safety must be 1st Priority - Safety of staff, contractors, and the public will always be the highest priority even if this means exceeding budgets or risking non-compliance.
- All other interests must be managed as the situation dictates and will out of necessity be a balance of some proportion (not necessarily equal proportions) between the interests:
    - Financial Stability – HCHI must be financially viable or it will not exist to manage other conflicts.
    - Quality of Supply – Customers want value and are willing to pay for a certain level of quality.
    - Electricity Rates – Rates reflect an appropriate balance between revenues and expenditures.
    - Compliance – Other than safety.

2.6 Accountabilities for Asset Management

HCHI's accountabilities for asset management are reflected in the following figure describing the corporate organizational structure and area of responsibility.



2.6.1 Accountability at Shareholder – Owner Level

HCHI is 100% owned by the holding company HCUI and HCUI is 100% owned by The Corporation of Haldimand County.

2.6.2 Accountability at Governance Level

HCHI is governed by a Board of Directors and the Directors are appointed by HCUI. HCUI also has a Board of Directors which is appointed by Haldimand County. HCHI has eight directors, four of which are independent from any affiliate.

2.6.3 Accountability at the Executive and Management Level

The President & CEO is accountable to the Board of Directors and the Management Level is accountable to the President & CEO through business goals, the development and execution of annual budgets, and various standards & processes that apply to the distribution system assets. Accountability for financial and regulatory activities lies with the Finance Manager. This role provides all financial reporting, asset funding provisions, and budgeting process for all phases of the DAMP.

Accountability for the daily continuity and restoration of electrical supply lies with the Operations Manager. This role provides control and dispatch for electrical restoration.

Accountability for the development of new assets lies with the Engineering Manager. This role addresses long term planning issues such as capacity and security.

Accountability for managing the lifecycle of existing assets and the installation of new assets is shared between the Engineering and Operations Manager who coordinate design, construction, and maintenance of the distribution assets.

2.6.4 Key Reporting Lines

The Board of Directors governs HCHI's electrical distribution business and manages this overall responsibility through the President & CEO.

The HCHI Board of Directors meets monthly and receives monthly reporting from management outlining financial, operational, and safety performance as well as the progress in maintenance, operational, and capital programs.

2.6.5 HCHI Operating Structure

2.6.5.1 Location

HCHI's operation is based in one centralized location at 1 Greendale Drive, Caledonia. All staff report daily to this location.

2.6.5.2 Operations Group

The Operations Department provides operating, emergency response, connection services, maintenance services, and capital construction services. This group in conjunction with contractors collects information required by the "Distribution System Maintenance & Inspection Program" in the management of existing assets. This group is also responsible for executing design plans including acquisition and warehousing of all material requirements and contracted services.

2.6.5.3 Engineering Group

The Engineering Department provides planning and design for new capital works and all new connections to the distribution system. This group analyses system configuration with such inputs as growth, new connections, voltage levels, and capacity information with a view to optimize the configuration of the distribution system.

2.6.5.4 Finance Group

The Finance Department provides financial reporting & analysis, budget support, accounting, rate design, and regulatory support to meet regulatory requirements.

3 Asset Management Systems

3.1 Asset Knowledge

Asset information is essential to a properly functioning asset management plan. HCHI has various records, both paper and electronic, which identify asset attributes and condition data. One of the objectives of the Asset Condition Assessment (ACA) by Kinectrics was to identify current gaps in information so that processes could be put in place to capture more data than HCHI is currently collecting. The following table summarizes the status of the collection of asset attributes (including nameplate information) with respect to each asset category (based on July 2009 information).

Asset Group (Matches Kinectrics Assignments)	Description of Asset	% Of Asset Attributes Known	% of Condition Data Collected
A	Distribution Station Transformers	100	95
B	Air Blast Circuit Breakers	100	0
C	Pole Mounted Transformers	100	0
D	Pad Mounted Transformers	100	0
E	Vault Room Transformers	100	100
F	Poles	84	62
G	Gang Operated Overhead Switches	0	0
H	Pad Mounted Switches	0	0
I	Underground XLPE Cable	0	0
J	Overhead Reclosers (Three Phase)	100	0

The method of information collection and storage is a key component to successfully managing the data from all assets. Records are kept in a number of formats either paper based files, database (MS Access-Db), or spreadsheet (MS Excel-Sp) based. The current status and type of HCHI's record keeping is noted in the table below. In addition to the type of record the ACA provided information on the data gaps with each asset type. These data gaps are grouped into three (3) categories P1 thru P3 with P1 the highest impact to P3 the lowest impact. The chart below summarizes the number of data gaps per asset category.

Asset Group (Matches Kinectrics Assignments)	Description of Asset	Record Type			# of Prioritized Data Gaps		
		Paper	Db	Sp	P1	P2	P3
A	Distribution Station Transformers	X	X	x	3	2	1
B	Air Blast Circuit Breakers	X			8	9	9
C	Pole Mounted Transformers		X				2
D	Pad Mounted Transformers		X			1	2
E	Vault Room Transformers		X			2	1
F	Poles		X			1	
G	Gang Operated Overhead Switches				2	4	2
H	Pad Mounted Switches				2	3	5
I	Underground XLPE Cable				2	4	
J	Overhead Reclosers (Three Phase)	X			10	6	4

From the above tables it is clear that a number of data gaps exist from both the attribute and condition categories of information.

3.2 Improving and Using Asset Knowledge

HCHI's strategy is to make the GIS platform the keystone of all asset information. Currently asset data, for poles and distribution transformers, such as global coordinates, asset number (unique ID #) and physical attributes are available or accessible directly from the map. Condition data is being collected (electronically) for poles and downloaded into discrete databases. In the future HCHI is confident that existing systems will be continuously improved so that all information (asset attribute and condition data) for all assets will be housed under the GIS format. This is essential in order to prepare meaningful asset condition assessments on a regular basis upon which replacement and development activities decisions can be made.

3.3 Key Systems and Processes

HCHI's key tool to manage asset knowledge is its ESRI Graphical Information System (GIS). This system in conjunction with a number of connected databases and spreadsheets residing on the outside of the main software platform contains the attributes and maintenance/inspection information for some of the distribution assets as noted in the above table. A graphical representation of the specific asset is placed on top of an aerial photo of the ground within the service territory of HCHI. This graphical representation presents a software link to the asset attributes collected in the system. In addition to the GIS, a number of paper records also exist which contain the asset information.

At present the population of asset information into the GIS system is ongoing and it is anticipated that by the end of 2010 all main attribute information will be complete for poles and transformers. The collection of this information in an electronic format has proven to be very valuable in terms of efficiency of collection, accuracy, and access.

In the future, asset information will be collected for the other assets as maintenance activities are implemented.

4 Summary of Assets Covered

4.1 Distribution Area

HCHI's distribution system covers approximately 1252 square kilometers bounded within the confines of Haldimand County. This area includes approximately 36 square kilometers of urban service territory and 1216 square kilometers of rural service territory. The urban territory includes five communities – Caledonia, Cayuga, Dunnville, Hagersville, and Jarvis. The rural territory includes farms (951 in total) with a mixture of livestock and crop production. Haldimand County is home to 45,212 residents. A map of the service territory is shown in Appendix B.

Generally speaking the urban service territory is comprised of mostly residential development with a supporting commercial area in each of the urban communities. The rural area is comprised mainly of farmland.

Haldimand County has industrial parks housing both general and heavy industrial uses. The industrial parks range from fully to lightly developed and in general there is lots of space for future development.

Haldimand County is described as follows:

> **In addition to its rural and agricultural roots, its lifestyle, tourism, recreation, and heritage, Haldimand County provides and excellent foundation for an economy that depends increasingly on industry. This foundation includes:**
>
> - **Strong, skilled workforce, with lower incomes than the provincial average;**
> - **One of Ontario's largest green field tracts designated for industrial development;**

- **Proximity to the 130 million people in the North American industrial heartland;**
- **And a well-developed industrial base and infrastructure.**

The above Haldimand County statistics and information is taken from a document titled "Haldimand County Economic Development – Community Profile 2008" published in December 2008.

4.1.1 Demographics

4.1.1.1 Key Economic Activities

Haldimand County is home to heavy industry, resource extraction, and small businesses. Small business includes a diversified agricultural sector with related industries and a growing tourism industry.

4.1.1.2 Energy & Demand Characteristics

Key energy and demand figures separated into transformer station areas and based on historical information from 2003 to 2008 are as follows:

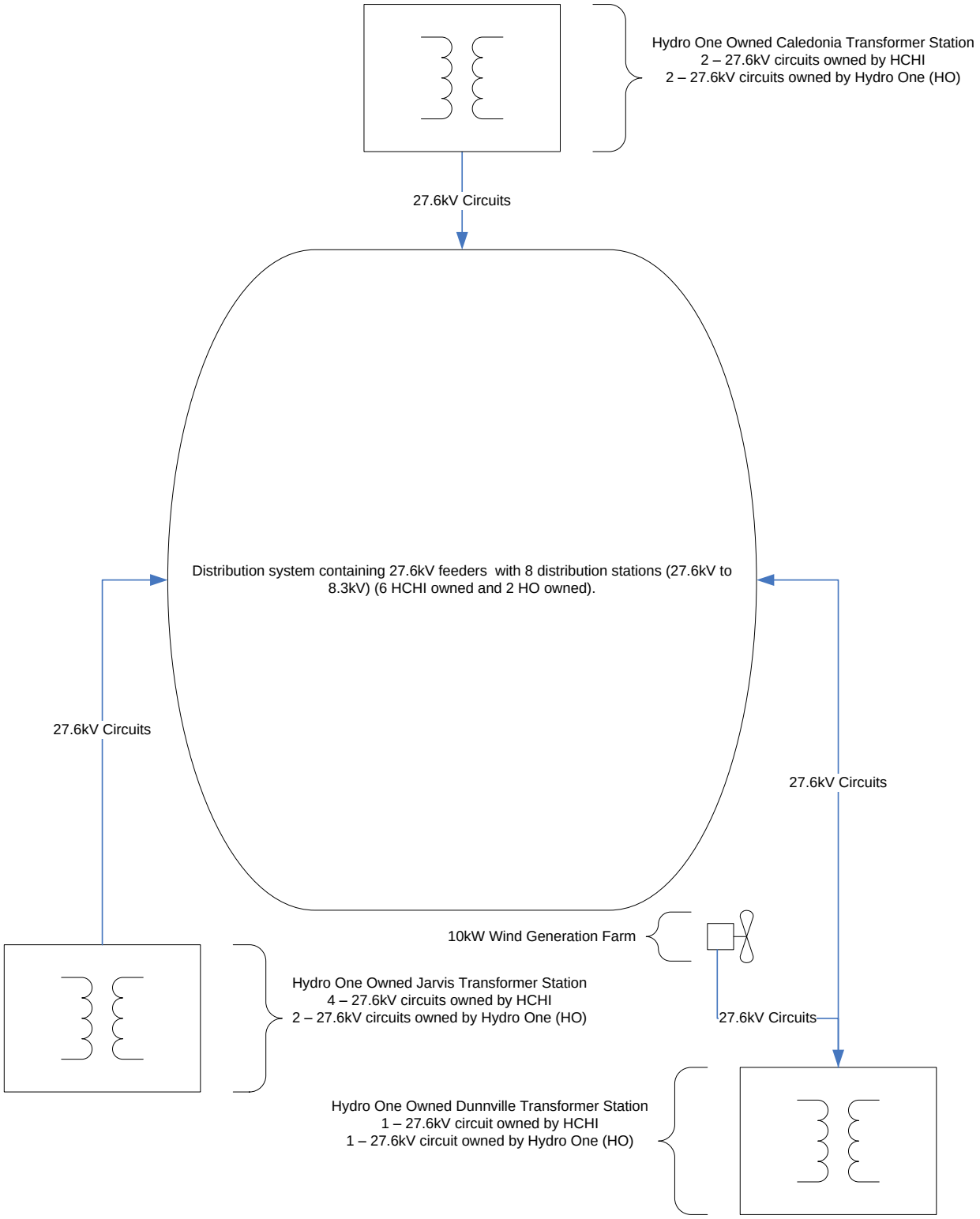
Transformer Station	Maximum Monthly Energy Usage	Maximum Monthly Demand	Long Term Trend GWh	Long Term Trend MW
Caledonia	20.7GWh	38.2MW	A downward trend in growth	Flat growth
Dunnville	11.5GWh	21.3MW	Flat growth	Slight downward trend
Jarvis	16.6GWh	25.3MW	A downward trend in growth	Downward trend

4.2 Network Configuration

HCHI is connected to the Ontario power transmission grid at three (3) transformer stations which are owned by Hydro One (HO). HCHI customers are supplied via twelve (12) 27.6kV circuits which emanate out of these transformer stations. Of the twelve circuits seven (7) circuits are owned by HCHI and five (5) circuits are owned by Hydro One. Within the service territory of HCHI there are also eight (8) distribution stations fed from the 27.6kV circuits. Six (6) of these are owned by HCHI and two (2) are owned by HO. Of the circuits and distribution stations owned by HO, HCHI has a number of customers fed from these circuits and stations. All of these HO owned circuits and stations are embedded in HCHI's service territory and supply loads beyond HCHI's border. Responsibility for maintaining circuits lies with the respective owners of the equipment.

There is also distributed generation on the system.

The basic configuration is shown below:



4.3 Assets by Category

HCHI has the following major assets:

Asset Group (Matches Kinectrics Assignments)	Description of Asset	# of Assets
A	Distribution Station Transformers	11
B	Air Blast Circuit Breakers	2
C	Pole Mounted Transformers	6753
D	Pad Mounted Transformers	473
E	Vault Room Transformers	3
F	Poles	27064
G	Gang Operated Overhead Switches	46
H	Pad Mounted Switches	10
I	Underground XLPE Cable	28 Feeders (81km)
J	Overhead Reclosers (Three Phase)	7

The above data is current as of July 2009. The pole count is an estimate because all poles have not yet been assigned an asset number. The asset categories by "letter" are the same as used in the Asset Condition Assessment (attached as Appendix G).

5 Managing the Existing Assets

Electricity assets like any other type of physical asset have a lifecycle. This section describes how HCHI assets are managed over their entire lifecycle from conception to retirement.

5.1 Maintenance Planning

HCHI manages assets with the intent of providing a safe, efficient, reliable, and cost effective electricity distribution system.

For example distribution transformers are manufactured with the intent that there is no need to provide regular maintenance (maintenance free) for the duration of their lifecycle. Generally speaking they remain in service providing continuous service until they reach the end of their lifecycle – they fail in service.

Some distribution assets remain in service delivering electricity with little required maintenance. However, a small percentage of the distribution assets such as substation transformers do require regular maintenance. These transformers generally supply many hundreds or thousands of customers and a failure would likely result in a lengthy outage and a significant number of resources to replace a failed unit. This maintenance involves regular condition testing which highlights or identifies possible problems.

The inspection and maintenance of distribution assets is detailed in HCHI's "Distribution System Maintenance and Inspection Program" attached as Appendix C. The maintenance and inspection program was first introduced in 2006 and is very much a work in progress. Prior to this time there was no documented program in place and records of maintenance or inspection

activities were either poorly organized or non-existent. The document is continuously being updated with new information upon which maintenance or inspections of equipment are based. Maintenance standards in the program are built upon manufacturer's recommendations, industry regulatory requirements, industry best practices, and HCHI's own experience with performing the maintenance or inspection. The document clearly describes the geographic area and frequency of programs, the specifications or standards for the work, who is responsible to carry out specific actions, the accounting job numbers associated with the work, and the forms necessary to document the field work.

The strategy behind this program was based on the fact that for the most part minimal maintenance had been performed or documented for the majority of distribution assets. The initial intent of the program is to provide base knowledge to provide enough information to make informed decisions on future maintenance. Initial intervals for maintenance may be changed based on actual experience with field data collected. For example, most of the maintenance forms have the following questions that are required to be filled out by the maintainer:

> Indicate which one of the following statements applies to this particular switch:
>
> ☐ A The maintenance was unnecessary; it could have been done later
> ☐ B The maintenance was performed at the right time; only normal maintenance was req'd
> ☐ C The maintenance should have been done earlier; major faults were found

This process will allow HCHI to collect information and base future intervals on the actual existing condition of the asset. In this way the cost to perform maintenance can be optimized. The data collected from the maintenance provides valuable information upon which to base repair work, refurbishment activities, and asset replacement schedules.

In addition to actual asset maintenance a number of programs exist to enhance the reliability of the assets or to identify problems with assets. These programs are as follows:

a) Infrared Thermography – An infrared patrol is conducted annually to detect hot spots in both overhead and underground equipment. Critical items identified are corrected immediately and non-critical items are scheduled for repair in conjunction with other planned work.
b) Line Clearing and Tree Trimming – Tree contacts are a major cause of distribution system outages and momentary interruptions for HCHI customers. HCHI has a regular line clearing and tree trimming maintenance program. This program cycles through the service territory on a five year basis.

5.2 Understanding Asset Lifecycles

Definition of Key Lifecycle Activities:

Activity	Detailed Definition
Operations	Involves changing the design parameters of an asset such as changes in circuit configuration or setting a tap setting on a transformer. Does not involve a physical change to the asset. Line clearing of trees is an operations activity.
Maintenance	Involves replacing consumable components on asset assemblies but not the whole assembly. Generally these sub components wear out before the whole assembly fails. For example an insulator on a pole assembly or an arc snuffer/muffler on a gang operated load break switch.
Sustainment	Involves replacing assets in terms of the assets listed under asset categories. For example replacing a pole in a pole line.
Betterment	Generally involves replacing a non consumable item like an overhead conductor with an item of greater capacity which does not increase the distribution system footprint. This type of activity is discretionary.
Extension	Involves building a new asset where none previously existed. For example extending a pole line to supply a new customer. This activity increases the distribution system footprint. From time to time this activity may require changes in upstream assets. Non customer related activities are discretionary.
Retirement	Removes an asset from the distribution system. For example removing a redundant pole line from service. By definition retirement would be a reduction in the distribution system footprint.

5.3 Operating the Assets

Operational activities generally arise in dealing with distribution system issues when assets are not operating as normal. For example a number of triggers exist as follows:

a) Voltage levels too high or too low – outside of Canadian Standards Association Voltage Variation Limits for circuits up to 1000V under “Normal Operating and Extreme Operating Conditions”
b) Fault current exceeds thresholds on protective devices such as reclosers, fuses, and breakers
c) Demand exceeds thresholds on protective devices and or the assets current carrying capacity
d) Customer concerns about the quality or reliability of electricity being supplied to them

5.4 Maintaining the Assets

As stated above maintenance is primarily about replacing consumable components of assets. Components wear out in a number of ways including oxidation, pitting or erosion of contact surfaces, material rot, gasket degradation, pitting of insulators, etc. Continued operations of devices which clearly exhibit component degradation will eventually lead to a failure in the distribution system. What leads to failure is a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycles, stress due to fault events, ambient temperature, contaminants, and the maintenance performed during the life of the asset.

Specific maintenance strategies such as run to failure or decisions to clean pad-mounted switchgear have been developed primarily based on past maintenance histories or the lack thereof and the information contained in the Asset Condition Assessment.

6 Service Levels

This section describes how HCHI considers its service levels and relates them to the distribution assets.

HCHI assesses what customers preferences are by obtaining informal feedback from customers during regular daily interactions with the utility. HCHI considers service levels to include a broad range of services including capacity, quality of electrical supply, continuity, restoration, ground clearances to conductors, grounding of equipment (public safety), and the absence of (radiant) interference.

HCHI considers customer preferences to fall into three categories in order of priority as follows:

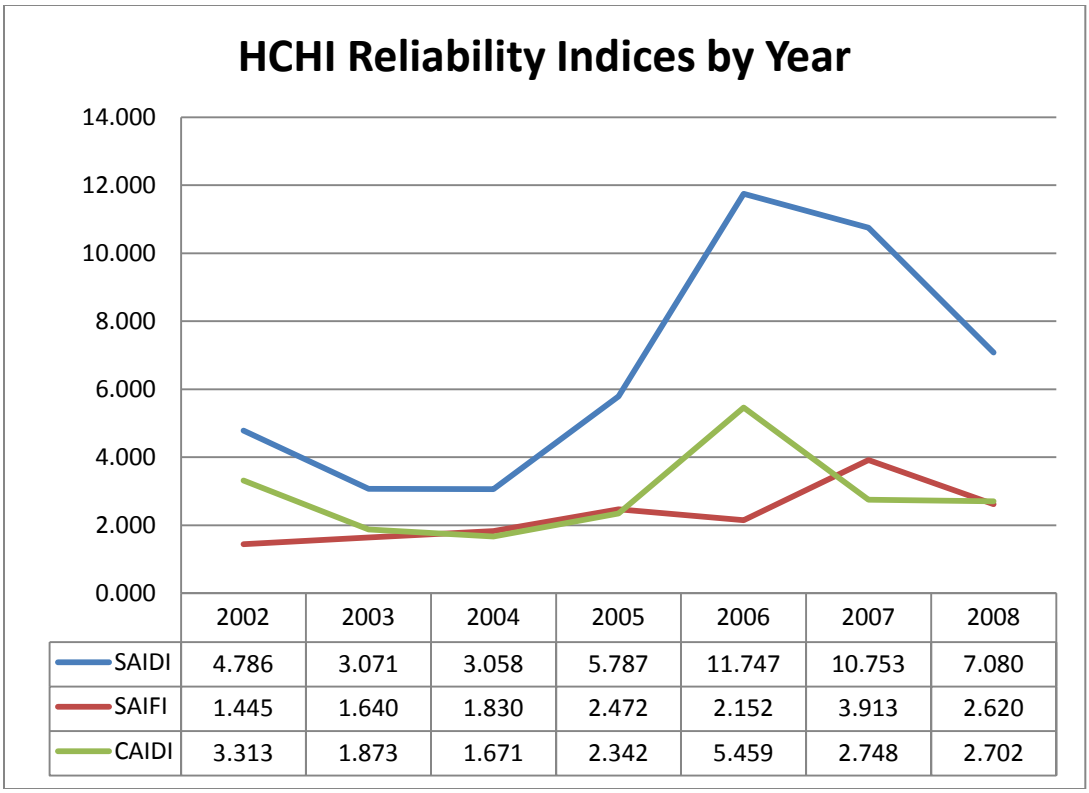
a) Reliability – continuity and reliability of electrical supply
b) Quality – the absence of momentary interruptions and non-standard voltage levels
c) Process – answering the phone, processing regular utility transactions such as new service connections & upgrades to electrical services, and outage notices

6.1 Service Levels - Reliability

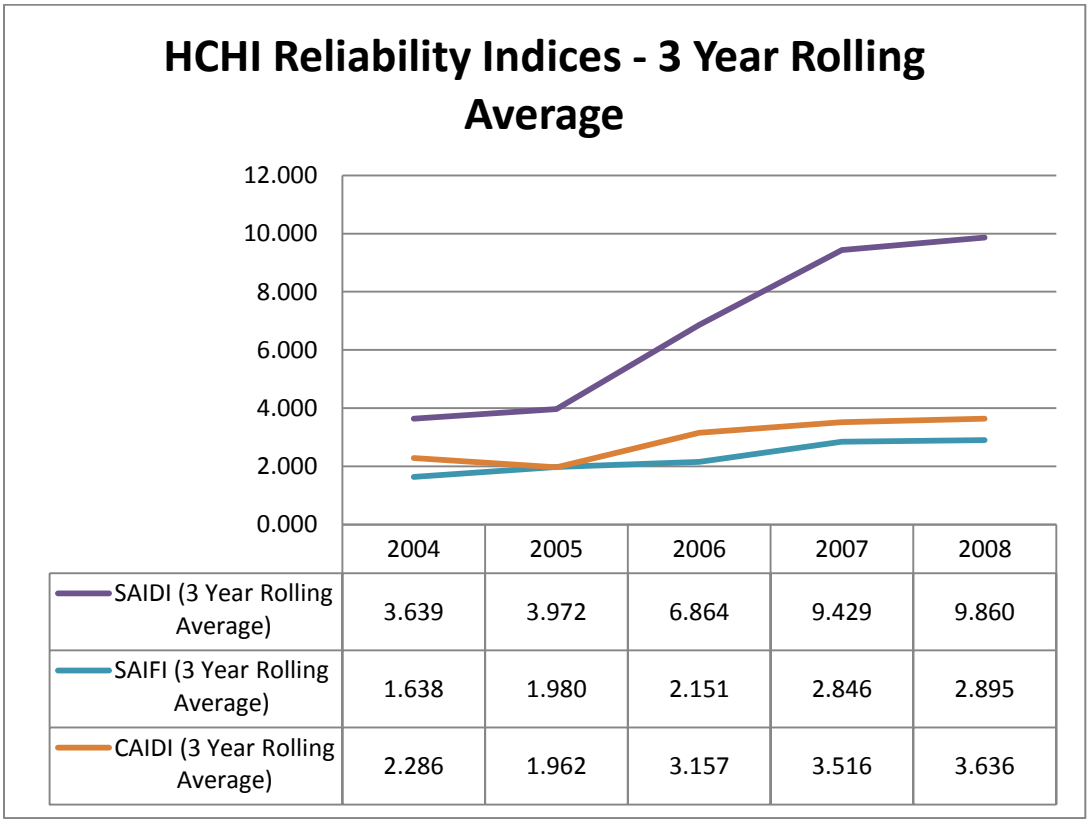
The reliability of supply is primarily measured by three internationally accepted indices called SAIDI, SAIFI, and CAIDI. They are defined as follows:

- SAIDI – System Average Interruption Duration Index – the length of outage customers experience in the year on average – expressed as hours per customer per year;
- SAIFI – System Average Interruption Frequency Index – the average number of interruptions each customer experiences – expressed as # interruptions per year per customer;
- CAIDI – Customer Average Interruption Duration Index – the speed at which power is restored – expressed as average duration in hours per customer per year.

HCHI's indices history is shown in the table below (includes loss of supply):



	2002	2003	2004	2005	2006	2007	2008
SAIDI	4.786	3.071	3.058	5.787	11.747	10.753	7.080
SAIFI	1.445	1.640	1.830	2.472	2.152	3.913	2.620
CAIDI	3.313	1.873	1.671	2.342	5.459	2.748	2.702



	2004	2005	2006	2007	2008
SAIDI (3 Year Rolling Average)	3.639	3.972	6.864	9.429	9.860
SAIFI (3 Year Rolling Average)	1.638	1.980	2.151	2.846	2.895
CAIDI (3 Year Rolling Average)	2.286	1.962	3.157	3.516	3.636

As shown by the graphs the levels of the indices has increased since 2005. This increase is believed to be significantly influenced by the accuracy of the reporting and the increased availability of data with respect to customer information. Since 2005 much effort has been placed on refining the reporting protocol for the reliability indices and now in 2009 this system is much improved. In addition to the reporting and data tracking process, information regarding the number of customers on each section of line has improved. Instead of an educated guess of a customer count (as occurred previously) the GIS system can actually tell us how many customers are on any given portion of the distribution system. This makes the reporting much more accurate.

The reliability of supply is affected by HCHI's sustainability programs (for existing assets), discretionary capital projects, operating processes (i.e. – switching protocols and use of faulted circuit interrupters), and factors which are not under the control of HCHI such as weather disturbances and motor vehicle accidents.

6.2 Service Levels - Performance of Circuits – 27.6kV and 8.3kV

Since the beginning of 2008 HCHI has been tracking the reliability of individual circuits. The information source for this particular statistic is the same database that is utilized in calculating the reliability indices in Section 6.1 above. The reliability indices per feeder for 2008 are shown as a table and are attached as Appendix D. It is HCHI's intent to utilize this information as an input into the prioritization of both maintenance and capital expenditures. This utilization will occur when year to year comparisons can be made.

6.3 Causes of Outages and Outages by Component

Since the beginning of 2008 HCHI has been tracking the causes of outages and the distribution components that cause outages. The information source for these particular statistics is the same database that is utilized in calculating the reliability indices in Section 6.1 above. The Outages by Cause for 2008 shown in two graphs is attached as Appendix E and the Outages by Component for 2008 shown in two graphs is attached as Appendix F. Both sets of graphs reflect outages in terms of customer hours and the number of incidents. It is HCHI's intent to utilize this information as an input into the prioritization of both maintenance and capital expenditures. This utilization will occur when year to year comparisons can be made.

6.4 Service Levels - Quality

Issues with quality of supply usually results in customer complaints. Measuring the response and actions to customer calls about poor quality is an indicator of the service level being provided. In a predominantly overhead system the control of momentary interruptions is a difficult one to reduce with any certainty because adverse weather and tree contacts affect this factor considerably. However, regular tree trimming, the installation of animal guards on all distribution transformer primary bushings, and the constant vigilance of eliminating system defects through inspection and maintenance is believed to have an impact. Low voltage is usually related to either a defective asset or a capacity issue.

6.5 Service Levels - Process

Process issues are generally the customer's perception of how HCHI goes about its business. The primary measure for this is the reception of customer complaints. In some cases these are relatively easy to fix with process management improvement practices but, they may also be

relatively expensive to fix. An example of this is the purchase of a new phone system to generate a better interface with the customer. Some service levels are required by OEB regulation and this allows HCHI to maintain a consistent level of service in these areas. Specifically the following services are measured:

a) Connection of New Services
b) Appointment Scheduling
c) Appointments Met
d) Rescheduling a Missed Appointment
e) Telephone Accessibility
f) Telephone Call Abandon Rate
g) Written Responses to Enquiries
h) Emergency Response

The above service levels are reported to the OEB as required annually.

6.6 Public Safety

Public safety in Ontario with respect to the electrical distribution system operated by HCHI is governed by Ontario Regulation 22/04 – Electrical Distribution Safety.

7 Sustaining Existing Assets

7.1 Assets by Category

HCHI's distribution assets are grouped as follows:

a) Distribution Station Transformers
b) Air Blast Circuit Breakers
c) Pole Mounted Transformers
d) Pad Mounted Transformers
e) Vault Room Transformers
f) Poles
g) Gang Operated Overhead Switches
h) Pad Mounted Switchgear
i) Underground XLPE Cable
j) Overhead Three Phase Reclosers

7.2 Asset Condition Assessment

The cornerstone of any asset management plan is to understand the type of assets, the number of assets, and the condition of the assets owned by the corporation. Prior to the initiation of the GIS system in approximately 2004 all records were kept in paper or spreadsheet form. As well, detail on the various asset numbers, attributes and their condition were generally poorly documented or unknown. With the evolution of the GIS system and various database development projects, data collection and retention has improved dramatically. Commencing in approximately 2004 transformer attribute information was collected and manually input into a database. This program was completed in early 2008. In 2006, in conjunction with plant inspections, pole attribute and condition data started to be collected electronically and downloaded into database format. At the time of writing this plan approximately 2/3rd to 3/4s of the poles in the distribution system have been mapped and information collected.

As a precursor to completing HCHI's rate application, due in August 2009, it was decided that a third party Asset Condition Assessment was warranted to substantiate HCHI's progress in asset management processes and validate work completed so far. As a result of this decision Kinectrics Inc. a well known independent consulting engineering company was contracted to perform an Asset Condition Assessment (ACA) of HCHI's electrical distribution assets as noted above. This took place in the 3rd and 4th quarter of 2008 with the report being delivered in the 1st quarter of 2009. The ACA dated March 10, 2009 is attached as Appendix G.

The objectives of the ACA were to:

a) Quantify the extent of deterioration of distribution assets;
b) Quantify the replacement of distribution assets over a future time period;
c) Assess the adequacy of HCHI's inspection and maintenance program; and
d) To produce a detailed report which will be utilized to:

    a. Support HCHI's cost of service rate application submission in 2009 to the Ontario Energy Board (OEB) for rates to be effective 2010;
    b. Provide a basis with which to build a long term capital plan for distribution assets.

The scope of the ACA was to include:

a) Assessment will include electrical distribution assets and exclude buildings, office equipment, tools, and mobile equipment;
b) Prioritize or rate, the risk of each asset category from highest to lowest, taking into consideration the condition, number of assets, and impact of failure to HCHI;
c) Provide a detailed summary on best practices within the electrical utility and general industry business sector on the asset deterioration process, failure modes, consequences of failure, and end of life criteria for all distribution assets;
d) Collect available asset attributes and condition data from HCHI records;
e) Extrapolate (if necessary) existing information to estimate numbers and conditions of assets which have not yet been documented for all distribution assets. This process shall follow statistically relevant protocols;
f) Analyze asset condition for the entire asset category and population to produce a replacement schedule for a twenty year replacement period;
g) Conduct a sampling survey/audit to verify information on assets contained in HCHI records and report findings;
h) Review the adequacy of HCHI's inspection and maintenance program and provide recommendations for improvement;
i) Review the adequacy of HCHI's record keeping systems/processes and provide recommendations for improvements;
j) Develop a risk based evaluation model and protocol for prioritizing distribution system capital expenditures; and
k) Develop Health Indices for all distribution asset categories and the overall distribution system.

The final output of the ACA was to recommend a replacement schedule based on a Heath Index Methodology (if possible). To this end only two categories of assets had enough condition data to make a forecast valid – namely distribution station transformers and poles. Replacement schedules for the rest of the asset categories were based on age with a distribution of

replacement related to industry best practices. The study also based its recommendations on a proactive or reactive strategy.

Specific conclusions reached as a result of the assessment summarized directly from Section 1.6 – Conclusions (Page 4) of the ACA are as follows:

a) HCHI's assets are generally in "Good" condition;
b) Pole replacement will be a main priority over the next twenty (20) years;
c) A significant number of data gaps were recognized for various asset categories;
d) HCHI's maintenance practices are compliant with the Distribution System Code (DSC) and are well suited for this utility.

HCHI has reviewed the ACA and in conjunction with its own practices has created a sustainment strategy for existing asset categories. When describing this strategy below and for purposes of this DAMP only summary information from the ACA will be used so as to not repeat the main content of the ACA in this document.

7.3 Sustainment Strategies

7.3.1 Distribution Station Transformers

7.3.1.1 Results of ACA

Distribution station transformers are one category of assets where fairly good condition and asset data exists within HCHI. Kinectrics calculated a health index for station transformers of seventy one (71%). Of the eleven (11) transformers in the system two (2) of these units have unknown age (illegible nameplates), five (5) units are older than fifty (50) years, two (2) units are between forty (40) and fifty (50) years, one (1) unit is between twenty (20) and thirty (30) years, and one unit is one (1) year old. The ACA also recommended replacements in year one of 2 units, year eight of 4 units, year eleven of 2 units, and one unit in each of years eighteen and nineteen.

7.3.1.2 HCHI Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) Most distribution stations are greater than forty (40) years old and the transformation based on age profile is reaching end of life in the range of forty (40) to fifty (50) years.
b) 8.3kV distribution plant is of a similar age to the substation transformers and is also reaching the end of life in the range of forty (40) to fifty (50) years.
c) As distribution plant is replaced it is built to 27.6kV standards.
d) Maintaining stations over the long term adds costs to the distribution system which would not be present if there were no stations at all. Eliminating stations does not generally require line extensions and the existing path or pole line is already in place.
e) The capacity of 27.6kV feeders assigned to HCHI from Hydro One already has the distribution stations embedded as part of their capacity. Therefore, converting the 8.3kV distribution plant to 27.6kV will not add load to the distribution or transmission system.
f) HCHI has enough spare substation transformers as back-up to transformers in service.
g) Testing of substation transformer oil is a very good predictor of when a transformer is reaching the end of its life. Regular testing allows time to make decisions about

transformer replacement and capital investment is therefore, based on a proactive approach.

These factors have led HCHI to adopt the following strategy:

a) Station transformers will only be replaced when there is a significant risk that a transformer will fail based on test results and recommendations by the service companies performing the testing.
b) Existing 8.3kv circuits will be converted to 27kv and the load taken off the 8.3kv distribution system – thus eliminating the need to replace substation transformers.
c) HCHI's capital budget process will include projects which will promote the retirement of the 8.3kv distribution substation assets.

7.3.1.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) There are no replacements scheduled for station transformers
b) Selkirk North DS is scheduled for retirement in 2009 (see Appendix H) – included in 2009 Budget
c) Jarvis DS is scheduled for retirement in 2011 – included in 5 year forecast (see Appendix J)

7.3.2 Air Blast Circuit Breakers

7.3.2.1 Results of ACA

Air Blast Circuit Breakers is one category of assets where the condition is very good. Kinectrics calculated a health index for air blast breakers of one hundred (100%). The two breakers in service are less than five (5) years old and although there is very little condition based information known HCHI is in a position to implement new processes to perform and report on the maintenance of these units. It would not be anticipated that these two units would require replacement in the next twenty years

7.3.2.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The breakers are new and are in very good condition. Proactive inspection and maintenance will reduce the risk of failure to and acceptable level.

These factors have led HCHI to adopt the following strategy:

a) Inspect, maintain, and monitor condition

7.3.2.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) There are no impacts on the budget – no replacements

7.3.3 Pole Mounted Transformers

7.3.3.1 Results of ACA

Pole Mounted Transformers have as a whole is a very large asset base. The age and condition of transformers is spread over a broad range. Kinectrics calculated a health index for pole mounted transformers of seventy four (74%). Unfortunately the age of approximately 70% of the population is unknown because this information was not captured in recent PCB inspections. Condition data is also very limited and will need to be addressed in future inspections. Over the next twenty (20) years it is estimated that two hundred and fifty nine (259) in year one to one hundred and nineteen (119) units in year twenty (20) will have to be replaced annually.

7.3.3.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The distribution transformer requires no maintenance.
b) The outage impact of an individual transformer failure is limited to a very small number of customers and in many cases due to the rural nature of the service territory only one customer is involved.

These factors have led HCHI to adopt the following strategy:

a) Inspect and monitor condition.
b) Replace when conditions dictate - such as cracked bushings, leaking oil, etc.
c) Replace when unit fails – thus, on a reactive replacement basis

7.3.3.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) Replacements are part of the Operations and Maintenance budget.

7.3.4 Pad Mounted Transformers

7.3.4.1 Results of ACA

The number of pad mounted transformers in the system is relatively small compared with the total number of distribution transformers. The age of the majority of units is less than twenty five (25) years and the condition of transformers are very good. Kinectrics calculated a health index for pad mounted transformers of ninety two (92%). Condition data is also very limited and will need to be addressed in future inspections. Over the next twenty (20) years it is anticipated that the number of replacements will increase from a minimum of three (3) in year one to a maximum of fifteen in year twenty (20) annually.

7.3.4.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The pad mounted distribution transformer requires very little maintenance. Maintenance is generally confined to replacing faded warning labels and potentially painting the units.

b) The outage impact of an individual transformer failure is limited to a very small number of customers.

These factors have led HCHI to adopt the following strategy:

a) Inspect and monitor condition.
b) Replace when conditions dictate - such as rusted tanks and frames, cracked bushings, leaking oil, etc.
c) Replace when unit fails – thus, on a reactive replacement basis

7.3.4.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) Replacements are part of the Operations and Maintenance budget.

7.3.5 Vault Transformers

7.3.5.1 Results of ACA

The population of vault transformers is limited to one installation and three (3) units. These units are nineteen (19) years of age and are in fair condition. Kinectrics calculated a health index for vault transformers of seventy (70%). Condition data is also very limited and will need to be addressed in future inspections. Over the next twenty (20) years it is not anticipated that these units would have to be replaced.

7.3.5.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) These vault transformers are located in a confined space. Working in confined spaces requires specialized training which is not currently available at HCHI.
b) These transformers are regular distribution transformers which require no maintenance.
c) The impact of an individual transformer failure is limited to one customer.

These factors have led HCHI to adopt the following strategy:

a) Inspect and monitor condition.
b) Due to the safety requirements for access, replace with a pad mounted or pole mounted transformer installation.

7.3.5.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) Not currently in the five (5) year forecast.
b) This would be a betterment as dictated in the discretionary capital program.

7.3.6 Poles

7.3.6.1 Results of ACA

Poles by far have the largest number of assets within the distribution system. The age and condition of poles covers the full range of possibilities from newly installed to sixty years for age and very poor to very good for condition. Kinectrics calculated a health index for poles of sixty nine (69%). Condition data is fairly good as the condition of poles is tested during the inspection process. Over the next twenty (20) years it is estimated that an increasing number of poles will need to be replaced annually numbering from three hundred and thirty one (331) in year one (1) to four hundred and thirty nine (439) in year twenty (20).

7.3.6.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The life expectancy of poles ranges from forty (40) to eighty (80) years and condition is affected by many factors such as the soil condition and loading.
b) HCHI's inspection procedure is regulated by the OEB and as poles are inspected a determination is made as to whether they need to be tested. If they are tested their condition is rated as replace ASAP, replace in two (2) to three (3) years, or retest in six (6) years. Their condition is therefore, readily known at regular intervals allowing time for budgeting and replacement before they fail and cause an emergency response.
c) A pole failure (depending on its function) can be a significant risk as the results of a failure could injure the public and result in lengthy interruptions in service to a widespread area and a large number of customers.

These factors have led HCHI to adopt the following strategy:

a) Inspect and monitor condition.
b) Replace when conditions dictate replacement – thus, a proactive replacement basis.

7.3.6.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) Replacement is part of HCHI's sustainment capital programs.
b) The budgets and forecast currently do not reflect the same number of replacements as indicated in the ACA. The current number of replacements are approximately 42% of those levels indicated the ACA. The actual number of replacements may have to be increased (or decreased) in the future to meet the actual number of poles identified by testing to be at end of life.

7.3.7 Gang Operated Overhead Switches

7.3.7.1 Results of ACA

Gang operated overhead switches are installed in limited numbers within the distribution system. The majority of gang operated overhead switches are less than twenty (20) years of age. Their condition is generally unknown due to lack of maintenance but because many switches are fairly new it is assumed that many are in very good condition. Kinectrics calculated a health index for gang operated overhead switches of eighty three (83%). Over the next twenty

(20) years it is estimated that one (1) or two (2) switches per year will need to be replaced after year four (4).

7.3.7.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The life expectancy of gang operated overhead switches is in the range of forty (40) years.
b) HCHI's Inspection and Maintenance program for switches is expected to begin in 2009. This program will allow better decision making in the near future with respect to switch maintenance and replacement.
c) A switch failure is low risk.

These factors have led HCHI to adopt the following strategy:

a) Inspect, maintain, and monitor condition.
b) Replace when conditions dictate replacement – thus, a proactive replacement basis.

7.3.7.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) Replacement is part of HCHI's sustainment capital programs.
b) The budgets for 2009 and 2010 do not have any replacements scheduled. The forecast reflects one replacement per year starting in 2011.

7.3.8 Pad Mounted Switch Gear

7.3.8.1 Results of ACA

Pad mounted switch gear units are installed in very small numbers within the distribution system. All switches are less than twenty five (25) years of age. Their condition is generally good to very good. Kinectrics calculated a health index for pad mounted switch gear units of eighty four (84%). Over the next twenty (20) years it is not anticipated that these units would have to be replaced.

7.3.8.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The life expectancy of pad mounted switch gear units is in the range of forty (40) years.
b) HCHI's Inspection and Maintenance program is expected to begin in 2009. This program will allow better decision making in the near future with respect to switch maintenance and replacement.
c) The impact of a switch failure is significant risk. A significant customer outage would likely occur and the safety of the public and staff would be potentially impacted.

These factors have led HCHI to adopt the following strategy:

a) Inspect, maintain, and monitor condition.
b) Replace when conditions dictate replacement – thus, a reactive replacement basis.

7.3.8.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) Future replacement would be part of HCHI's sustainment capital programs.
b) There are no plans for replacement within the next twenty (20) year period. The budgets and forecast reflect this.

7.3.9 Cross-Linked Polyethylene (XLPE) Underground Cables

7.3.9.1 Results of ACA

Cross-linked polyethylene (XLPE) underground cables are installed in mostly underground fed residential subdivisions. A small portion of cable serves as feeder egresses from stations and underground sections of feeders where necessary. HCHI has no lengthy sections of underground cable in its feeder egresses from stations to the load centres. These feeders are predominantly overhead conductor. All cables are less than twenty five (25) years of age and most cables are less than fifteen (15) years of age. Their condition is generally very good. Kinectrics calculated a health index for cables of eighty nine (89%). Over the next twenty (20) years it is anticipated that a number of segments will have to be replaced.

7.3.9.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The life expectancy of cross-linked polyethylene (XLPE) underground cables (of the newer variety – TRXLPE) is in the range of forty (40) years. However, older cables which were built with the technology available at the time of manufacture have an uncertain life expectancy (per Kinectrics report).
b) HCHI's Inspection and Maintenance program covers the terminations of cable only – these are exposed in pad mounted equipment and riser poles. Cable condition is only known for cables which fail in service. This information is tracked as part of the "cause" reliability statistics. Cable replacement decisions would be based on failure history. There have been very few cable failures in the last several years at HCHI.
c) The impact of a cable failure is low risk. Customer outages are likely to remain within a residential subdivision and all cables can be isolated due to a loop system design (there is usually another way to supply the load).
d) The safety of the public is not likely to be impacted because the cables are buried and not exposed.

These factors have led HCHI to adopt the following strategy:

a) Monitor the number of cable failures.
b) Create systematic replacement program when failure results indicate a systemic failure of that particular age or type of cable – thus, a reactive replacement basis.

7.3.9.3 Budgets and Forecast

The impact of the above strategy on HCHI's budget and or forecast is as follows:

a) Future replacement would be part of HCHI's sustainment capital programs.

b) There are no plans for replacement within the next twenty (20) year period. The budgets and forecast reflect this.

7.3.10 Overhead Reclosers (Three Phase)

7.3.10.1 Results of ACA

Overhead reclosers (three phase) units are installed in very small numbers within the distribution system. These units are relatively new to the system and all have been installed within the last five (5) years. Since the original installation all but one (1) of the units (all from one manufacturer) has failed. In 2008 a different manufacturer was selected, replacement units were procured, and all but one of the original units has since been replaced. Kinectrics calculated a health index for overhead reclosers (three phase) units of sixty seven (67%). However, this information is now out of date due to the replacement program. Over the next twenty (20) years it is not anticipated that these units would have to be replaced.

7.3.10.2 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The life expectancy of overhead reclosers (three phase) units is in the range of forty (40) years.
b) HCHI's Inspection and Maintenance program for reclosers is not yet fully defined. Due to the age of the units this is not critical at this time.
c) The one remaining unit of the original manufacturer will be monitored to assess its condition.
d) The impact of a recloser failure is a significant risk. A significant customer outage would likely occur and the safety of the public and staff would be potentially impacted. However, power restoration in the case of a failure is easy to accomplish by the closing of by-pass switches. This limits the duration of the interruption.

These factors have led HCHI to adopt the following strategy:

a) Inspect, maintain, and monitor condition.
b) Replace when conditions dictate replacement – thus, a proactive replacement basis.
c) Replacement is part of HCHI's sustainment capital programs.

7.3.11 Voltage Regulators

7.3.11.1 Results of ACA

Voltage regulators were not part of the ACA. However, they are a significant part of the distribution system which could affect customer service levels. They are therefore, being included in this DAMP.

7.3.11.2 HCHI Asset Condition Assessment

Voltage regulators are installed in very small numbers within the distribution system. There are two (2) sets of single phase regulators (pole mounted) and one (1) three phase regulator (station type design) in use. One set of regulators is less than ten (10) years old, one set is of unknown age, and the station type unit is forty nine (49) years old. The condition of the newest set of regulators is very good, the set of unknown age is fair, and the station type unit is fair.

7.3.11.3 HCHI's Sustainment Strategy

HCHI's sustainment strategy is predicated on the following factors:

a) The life expectancy of voltage regulators is between forty (40) to fifty (50) years.
b) HCHI's Inspection and Maintenance program for the pole mounted units is not yet fully defined. The oldest pole mounted units are currently being maintained and future maintenance activities will be based on the findings of this maintenance. The station unit is maintained in a similar fashion to station transformers and its condition is therefore, closely monitored.
c) The impact of a regulator failure is a significant risk. Depending on the time of year customer service levels with respect to low voltage situations would be a significant issue. The safety of the public would also be potentially impacted.

These factors have led HCHI to adopt the following strategy:

a) Inspect, maintain, and monitor condition.
b) Replace when conditions dictate replacement – thus, a proactive replacement basis.
c) Replacement is part of HCHI's sustainment capital programs.

8 Discretionary Capital Projects

Apart from the sustainment of existing assets in the distribution system there are other types of investment required in the distribution system. The first type can be called demand expenditures and they are required to supply the needs of a new customer or to enhance reliability in an area where system capacity is constrained. The second type of expenditure is called discretionary. These expenditures alleviate potential risks associated with the utility's goals.

8.1 Typical Considerations in Developing New Discretionary Projects

Typically new assets are required as a result of the following drivers:

a) Load Growth
b) Security of Supply and Level of Redundancy
c) Capacity of Assets
d) Voltage Regulation
e) Safety – Public and Staff
f) Environmental Compliance

8.1.1 Load Growth

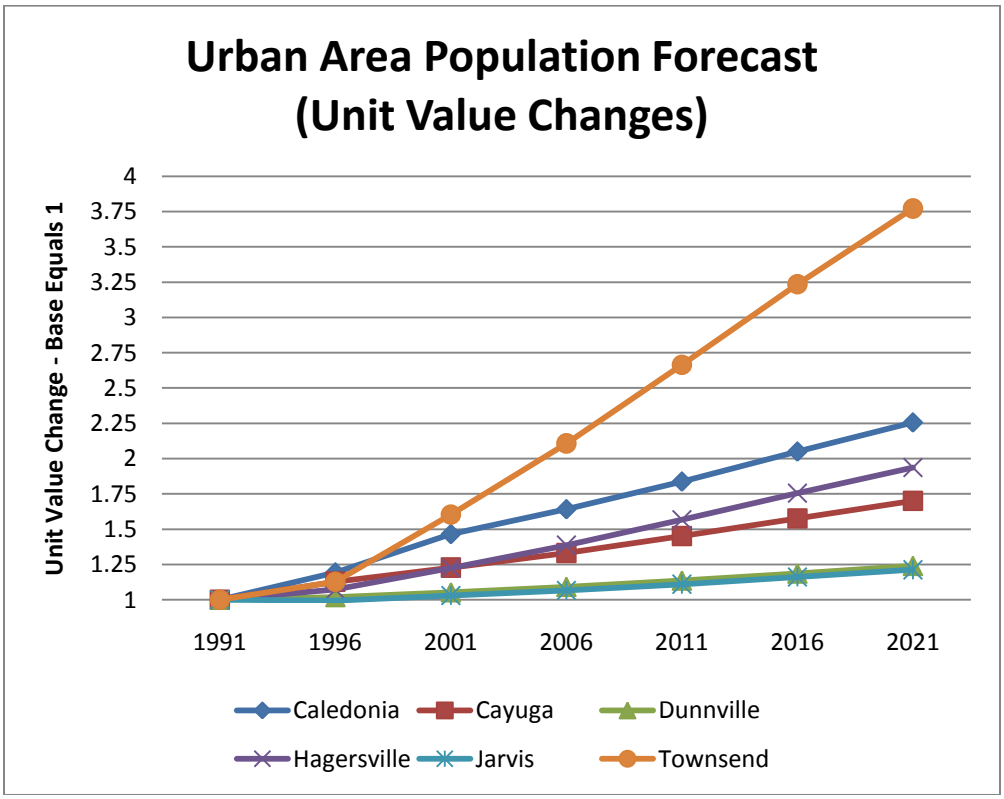
Load growth is influenced by a number of factors including:

a) Population Growth
b) Economy
c) Effectiveness of conservation programs

In order to determine how growth might affect the distribution system a number of areas need to be analyzed. These include population forecasts, the number of new connections, the type of connections, and historical demand.

8.1.1.1 Population Growth

The forecasted population growth for the urban areas within the County as published in the document titled "Haldimand County Economic Development – Community Profile 2008" published in December 2008 is shown below. The graph shows the unit value change in percentage (year to year) from a base of 1 in 1991.



The population counts for the above graph are shown in the table below:

	1991	1996	2001	2006	2011	2016	2021
Caledonia	6,375	7,605	9,335	10,460	11,710	13,065	14,380
Cayuga	1,405	1,585	1,725	1,870	2,040	2,215	2,390
Dunnville	5,415	5,515	5,700	5,910	6,150	6,420	6,715
Hagersville	2,355	2,525	2,885	3,265	3,690	4,135	4,560
Jarvis	1,365	1,355	1,405	1,455	1,515	1,585	1,655
Townsend	745	840	1,195	1,570	1,985	2,410	2,810
Totals	17,660	19,425	22,245	24,530	27,090	29,830	32,510
Percent Change					10	22	33

Clearly the urban population is expected to rise by thirty three (33) percent between 2006 and 2021 - on average 2.2 percent per year.

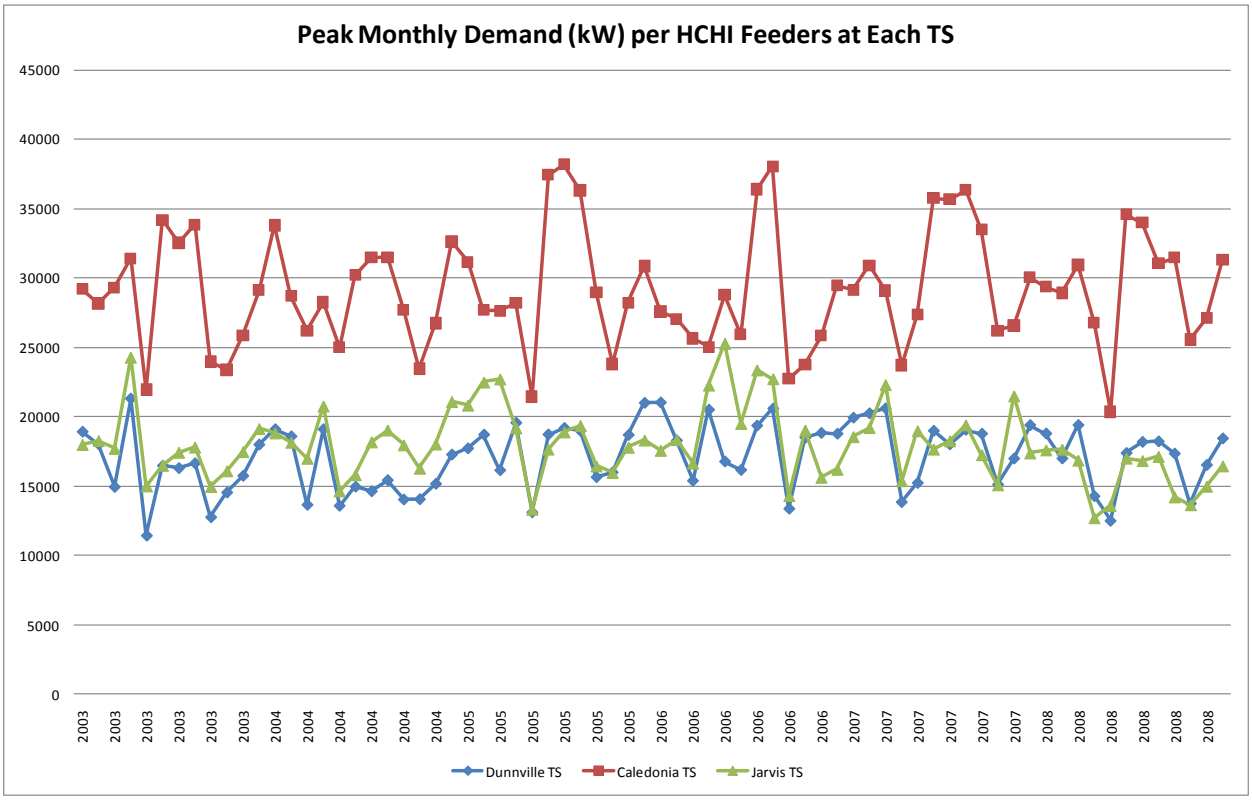
8.1.1.2 Number of New Connections

HCHI's new connections have slowed over the last six months compared with the previous four (4) years. However, the year to year totals show a fairly stable pattern. The following table shows the specifics. It should be noted that these connections represent low voltage connections.

	2005	2006	2007	2008	2009
January	9	20	15	15	5
February	15	15	8	14	3
March	6	17	7	10	4
April	13	9	3	6	12
May	17	21	52	14	11
June	14	11	19	17	
July	16	13	13	20	
August	19	16	18	18	
September	16	29	21	26	
October	23	17	26	24	
November	20	21	19	20	
December	12	8	11	3	
Totals	180	197	212	187	35

8.1.1.3 Peak Demand

HCHI has been recording the monthly demand peaks at each of the three (3) TS's. The data from each station for the period from 2003 to 2008 is shown in the following graph:



The demand is based on hourly data provided from the IESO which is not adjusted for losses and monthly peaks between stations are not coincident. It is clearly evident that there no distinct growth pattern in the peak demand for any of the TS's. Also evident is that 2005 & 2006 produced slightly higher demand and the peaks at each station are very stable. Both Jarvis TS and Dunnville TS have a slightly negative trend from 2006 to 2008.

8.1.1.4 Conclusion

Although the economy is currently very slow it is none the less expected to grow over the twenty (20) year timeframe of this plan. At this time it is unclear how the population growth will specifically affect the distribution system. Growth over the period from 2003 to 2008 has not appreciably affected the peak demand. However, population growth of 33% in the urban areas would likely require increased capacity and additional distribution lines to meet the increase in demand. Future revisions of this plan will need to account for this growth as and if it materializes.

8.2 Discretionary Capital Projects Prioritization Model

As part of the Asset Condition Assessment, Kinectrics was asked to assist HCHI with the development of a "Discretionary Capital Projects Prioritization Model" which could be utilized to set project priorities. The development of this model is described in detail in Kinectrics Report # K-014704-RA-0002-R02 and is attached as Appendix M.

The premise of the model is to evaluate each individual project given a number of business values. Each business value is rated for risk combining likelihood and consequence. The risk is given a value based on an exponential probability curve. Each business value is rated based upon the effect on attributes about the distribution system before and anticipated after the project is constructed. The risk score is weighted for each business value and a delta risk score is calculated. The cost of the project is then divided by the delta risk value to produce a dollar cost per unit value of delta risk. This method of evaluating each project allows the dollar cost per unit value of delta risk to be compared against other projects. Ideally the lower the dollar cost per delta risk value the more attractive the project will be.

The model considers six (6) business values and the attributes of these values are called business value attributes. These values have been defined in reference to HCUI's Strategic Plan developed in 2006. They have been assigned weights to reflect their impact on HCHI's business. They are as follows:

Business Value (BV)	Business Value Attribute (BVA)	Weight (% of Total)
Business Efficiency Reliability Performance	Status of Detailed Project Design	10
	Impact on SAIDI and SAIFI	25
	Impact on Voltage	
Community Relations Safety	Community Impact	20
	Eliminating Preventable Public Accidents	25
	Eliminating Preventable Work Place Accidents	
	Managing Property Damage Claims	
Regulatory Interface Environmental Stewardship	Regulatory Compliance	10
	Environmental Spills	10

In addition to the above business values some projects have direct financial savings. These savings are derived from the fact that HCHI is levied a "Sub-transmission (ST)" (formerly called Low Voltage) charge from Hydro One when HCHI's customer is fed from Hydro One distribution plant. The present value of these savings is used to offset the cost of the project before a dollar per delta risk score is calculated. Although the savings do not reflect the fact that HCHI will incur costs to maintain the new distribution assets it is felt that an offset is still relevant.

It should be noted that sustainment type projects are not evaluated using this model. Sustainment projects are not discretionary because an existing asset is at the end of its useful life and must be replaced. There is no discretion involved.

8.3 Past Capital Project Decision Process

In preparation for the setting of the budget of any given year, the projects in the five year capital plan and any new projects, which have arisen throughout the year, are evaluated for potential inclusion in the current year's project priorities. Each project is evaluated giving consideration to the following factors and sub-factors:

- Financial
  - Reduction of future operating costs
  - Elimination of sub-transmission charges
  - Reduction of losses
- Reliability
  - Impact to SAIDI, SAIFI, and power quality (low voltage, etc.)
- Safety
  - Public
  - Staff
- Customer Relations
  - Impact/effect on customers
- Regulatory
  - Compliance with regulatory statutes
- Environmental
  - Elimination of risk of contamination to the environment – oil spills

Once the priorities are decided, a preliminary project plan and estimate is made for each project. It is important to note that HCHI developed the prioritization model after the 2009 and 2010 budget process was finalized.

8.4 2009 and 2010 Discretionary Capital Projects

The discretionary projects in the 2009 and 2010 budgets were evaluated using best engineering judgment based on the experience of the Engineering Manager and the Operations Manager. The criteria used is noted above in Section 9.3

For purposes of this DAMP all 2009 and 2010 projects have been evaluated using the model. The detailed results are shown in Appendix H and I. In addition to the calculations for the model each project is described in terms of the business values.

The results of the model are shown in the table below:

Summary of Projects (2009 & 2010 Budget)	$/Delta Risk Score	Cost of Project
Eliminate Selkirk North DS	-8740	$ 295,000
Moulton Sherbrooke Townline - Rattlesnake Conv	1949	$ 148,000
Alder Street, Dunnville - Conversion (Phase 1 - Civil Works)	2768	$ 300,000
Concessions 12 to 17 - Eliminate 57M3 Supply Points	3168	$ 160,000
Eliminate Feeds from Lythmore Distribution System (Phase 1 - East)	3400	$ 127,000
Conversion to Supply Innophos & Sherbrooke Area to 31M1 Feeder	3724	$ 197,000
Central Lane Phase II Conversion - Dunnville	3896	$ 135,000
Lakeshore Road Re-Build (Phase 2)	5958	$ 300,000
Purchase HO Argyle DS F2 Feeder	6547	$ 200,000
Lakeshore Road Rebuild (Melville Lane)	16739	$ 346,500

This system of evaluation is very much a work in progress and it will be necessary to use this system for a number of years in order to refine the approach. For some of the above projects the sub-transmission costs have not been individually calculated. Therefore they were not included in the analysis. However, they do exist so in the future they will be used to redefine the priorities in the list. Notwithstanding the recent development of the model this approach will enable all projects going forward to be evaluated on a consistent basis. With time, HCHI should be able to determine appropriate thresholds for the dollar per delta risk score which make projects either acceptable or not.

8.5 Five Year Forecast

HCHI's Five Year Capital Forecast (attached as Appendix J) makes reference to specific projects for 2011 to 2013. These projects have not been prioritized using the prioritization model but descriptions for specified projects are included in Appendix K & L (2011 and 2012 respectively) in the same format as those included for the 2009 and 2010. These projects are in the most preliminary stages of the design process so the uncertainty about costs and detailed engineering design is high. In each of the years an allowance has been forecast to bridge the gap between specific projects and the projected spending level.

Appendix A - Summary of Assets (as at December 31, 2008)

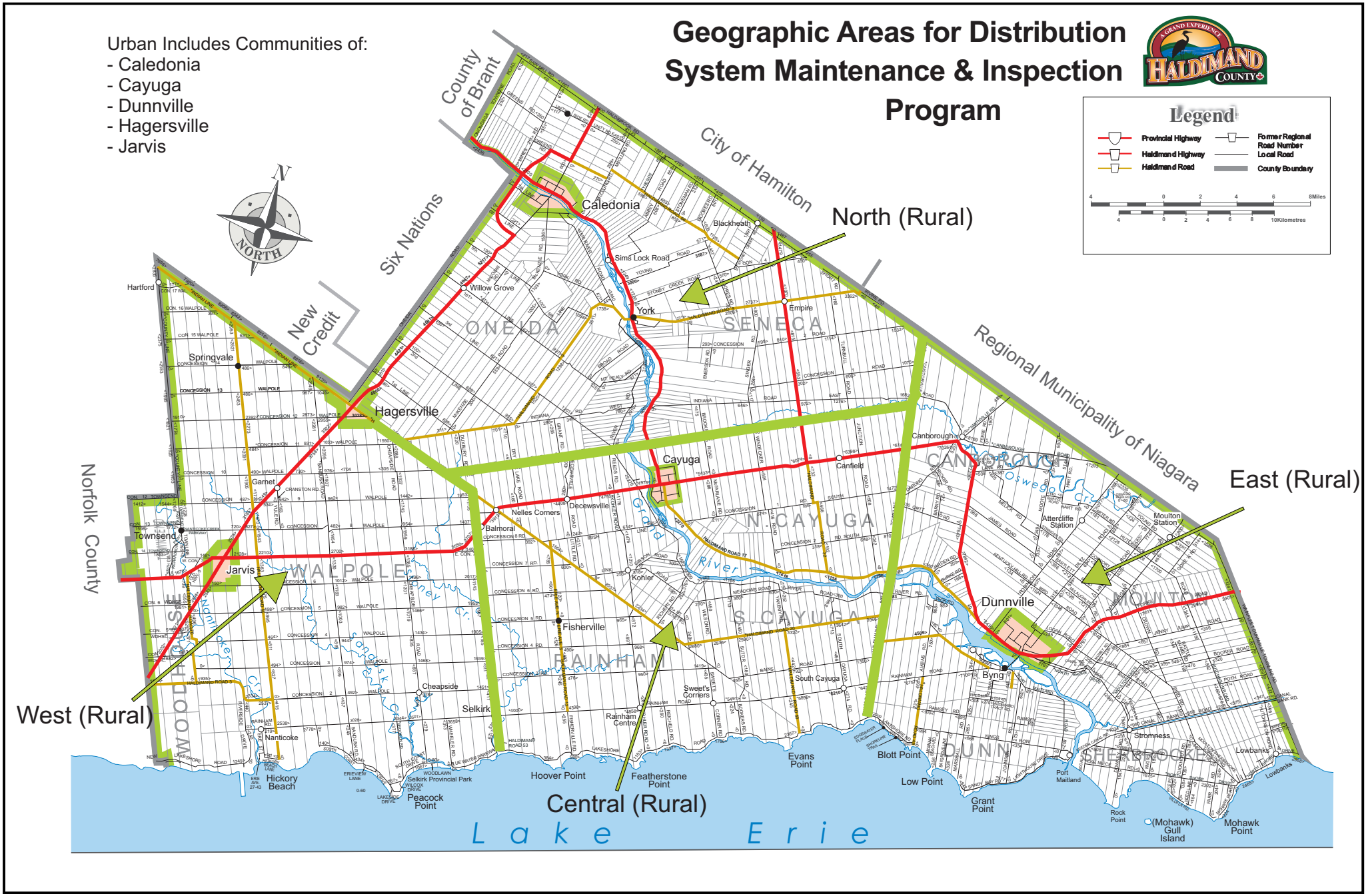
Category		Original Cost	% of Total
Distribution Stations	$	580,903	1.3%
Distribution Lines - Overhead	$	23,707,543	54.9%
Distribution Lines - Underground	$	6,941,095	16.1%
Distribution Transformers	$	11,961,649	27.7%
Total	$	43,191,190	

Detail extracted from Haldimand County Hydro Inc. – Audited Financial Statements 2008

Appendix B - Service Territory

Geographic Areas for Distribution System Maintenance & Inspection Program

Urban Includes Communities of:
- Caledonia
- Cayuga
- Dunnville
- Hagersville
- Jarvis



Appendix C - Distribution System Maintenance and Inspection Program

HALDIMAND COUNTY HYDRO INC.

Distribution System Maintenance and Inspection Program

Haldimand County Hydro Inc.
Distribution System Maintenance and Inspection Program
July 2009

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HALDIMAND COUNTY HYDRO INC.

Distribution System Maintenance and Inspection Program

1 General

1.1 Introduction

A Distribution System Maintenance and Inspection Program is a key component to system reliability, customer/public safety and worker safety. The purpose of this program is to document the requirements for the maintenance or inspection of all key distribution system assets. Each distribution system asset has its own program and within each program a procedure is identified as to how the maintenance and inspection will be performed. The procedure identifies the specific asset and assigns responsibility for the delivery of the program.

It is noted that this procedure is not yet fully complete. The program includes completed sections on assets which have established protocols and on assets which are in the process of being implemented. Assets for which the program has not been initiated are in a preliminary state and information in this document may only be the basic template information. Each program identifies whether the program is *established*, in the *implementation* phase, or is in the *development* phase.

This procedure is reviewed annually and is subject to the continuous improvement process.

The following maintenance and inspection programs are detailed in this procedure:

- Line Clearing and Tree Trimming Maintenance Program
- Substation Maintenance Program
- Distribution Plant Inspections
- Off Road High Voltage Line Inspections
- Thermography Inspection Program
- Switch Maintenance Program
- Hydraulic Reclosure Maintenance Program
- Electronic Reclosure Maintenance Program
- Voltage Regulator Maintenance Program

2 Programs

2.1 Line Clearing and Tree Trimming Maintenance Program

2.1.1 Introduction:

The purpose of this program is to clear all lines from the encroachment of trees and branches to eliminate, as best as possible, tree contact with lines. Haldimand County has many areas and community centres with mature trees. This is a major contributor to improved reliability.

2.1.2 Status of Program

Established

2.1.3 Definition of Geographic Areas and Frequency of Program:

This program is organized on a five year rotating cycle. The boundaries of each tree trimming area are based on the former townships and urban community centres. The areas are defined as follows:

- Urban — includes the urban communities of Caledonia, Hagersville, Jarvis, Cayuga, and Dunnville.
- North — includes townships of Oneida and Seneca.
- East — includes townships of Canborough, Moulton, Sherbrooke, and Dunn.
- Central — includes townships of North Cayuga, South Cayuga and Rainham.
- West — includes townships of Walpole, Woodhouse, and Townsend including the rural community centre of Townsend.

See Map included as Appendix A

The timing of each geographic area as completed in the past, present, and future is as follows:

			Geographic Areas				
Cycles	Part	Year	Urban	North	East	Central	West
1	1	2002	X	X			
1	2	2003			X		
1	3	2004				X	
1	4	2005					X
2	1	2006	X				
2	2	2007	X	X			
2	3	2008			X		
2	4	2009				X	
2	5	2010					X
3	1	2011	X				
3	2	2012		X			
3	3	2013			X		
3	4	2014				X	
3	5	2015					X

Sometimes it is not possible to perform clearing in the entire geographic area and adjustments are made by utilizing the former township names. Where there have been minor modifications to the schedule they are noted below:

- Cycle 1 – Part 1 - 2002 – Urban and North
- Cycle 1 – Part 2 - 2003 – East excluding Dunn
- Cycle 1 – Part 3 - 2004 - Central plus Dunn
- Cycle 2 – Part 1 - 2006 – Urban (Dunnville & Cayuga only)
- Cycle 2 – Part 2 - 2007 – North (plus Jarvis, Hagersville, and Caledonia)
- Cycle 2 – Part 3 - 2008 – East (Canborough, Moulton, and Sherbrooke only)
- Cycle 2 – Part 4 - 2009 – Central (plus Dunn)

2.1.4 Line Clearing Specifications

All trees, limbs and branches shall be trimmed so that the minimum clearance to the nearest conductor is:

- 4 meters for all primary (high voltage) distribution lines
- 1 meter for all secondary (voltages less than 750V) lines

Note – these specifications are the same as the Ontario Electrical Safety Code Rule 75-326(2) (Tree Trimming)

In locations where it would be considered inappropriate to trim to such clearances then the Contractor will consult with and obtain approval from HCHI for alternate clearances.

Prune all branches to direct growth away from the conductors. Any dead wood that is clear of the lines but is above or adjacent to the lines shall be removed.

All primary services supplying HCHI customers are to be cleared within the road allowance or within 20 meters of the main distribution line if off road.

All secondary services supplied from a transformer or secondary bus on the main line to be cleared to the house.

2.1.5 Responsibility

Administration of the Program	Operations Manager.
Work Protection	Lines Supervisor

2.1.6 Job Number

Job # - 01.5135.002
Title – Mtce Tree Trimming – Annual Contract (Primary)

2.2 Substation Maintenance Program

2.2.1 Introduction

The purpose of the Substation Maintenance Program is to identify any issues and remediate them as quickly as possible to ensure continuous operation of each substation and eliminate any danger to the public. This program consists of monthly inspections, annual oil analysis of all substation power transformers, and routine station maintenance.

2.2.2 Location and Identification of Substations

The substations that are part of this program are as follows:

Substation Name	Address	Installed Capacity (MVA)	# of Trans	# of Banks	# of Recl's	# of Fdrs
Canfield DS	105 Highway 56, Canfield	5	1	1	9	3
Decewsville DS	2283 River Road, Cayuga	5	1	1	6	2
Decewsville RS	315 Decewsville Road, Cayuga	15	1	1	0	1
Dunnville DS	1105 North Shore Drive, Dunnville	5	1	1	0	2
Jarvis DS	1423 Haldimand Road 55, Jarvis	5	2	?	6	3
Selkirk North	112 Selkirk Street, Caledonia	3	3	1	3	1
Selkirk South	71 Selkirk Street, Caledonia	5	1	1	0	2
Jarvis DS	1423 Haldimand Road 55, Jarvis	2	1	1	6	2

Note – Above table taken from file T://Operations/Asset Information/Substation Information/General Information/*General Substation Transformer Information incl Fuse Size*

2.2.3 Monthly Substation Inspection

2.2.3.1 Introduction

This purpose of this inspection is to identify any deficiencies and to verify that the substation is not going to pose any safety concerns to the public. Each station has a specific checklist which is to be completed and signed off by the inspector. A sample form is included in Appendix B.

2.2.3.2 Status of Program

Established

2.2.3.3 Responsibility

Completing this Inspection	Meter Supervisor.
Administration of Deficiencies	Operations Manager.

2.2.3.4 Job Number

Job # - 01.5016.002
Title – Ops Dist. Stn Equip – Station Check (Primary)

2.2.4 Annual Oil Tests

2.2.4.1 Introduction

Oil tests on substation transformers have been proven effective in identifying internal transformer issues before major faults occur which reduce reliability and increase cost. HCHI will perform both oil quality and gas-in-oil tests at least once per year. Additional oil tests will be completed upon recommendations by the service firm providing the analysis and as required.

2.2.4.2 Status of Program

Established

2.2.4.3 Responsibility

Administration of Program	Operations Manager.
Administration of Deficiencies	Operations Manager.

2.2.4.4 Job Number

Job # - 01.5016.003
Title – Ops Dist. Stn Equip – Oil Samples (Primary)

2.2.5 Routine Station Maintenance

2.2.5.1 Introduction

In order to ensure the reliability of each station the station shall be taken off line and maintained at regular intervals. This will provide the opportunity to check all electrical connections, inspect the equipment condition, perform tests if necessary, inspect and clean all insulating devices, switches and protective devices.

In the past it is uncertain as to what type of maintenance has been completed at each station. Therefore, as an initial step, each station will be taken off line in a three year period. This initial maintenance will establish a benchmark for the maintenance activity to follow. Subsequent maintenance activities will occur at approximately ten year intervals. The schedule is as follows:

			Substations						
Cycles	Part	Year	Jarvis	Selkirk N	Decewsville RS	Decewsville DS	Canfield	Dunnville	Selkirk S
1	1	2007	X	X					
1	2	2008			X	X	X		
1	3	2009						X	X
2	1	2018			X	X			
2	2	2019					X		
2	3	2020							X

Note – Nanticoke DS taken out of service in 2008. Selkirk North DS scheduled to be taken of service in 2009. Jarvis DS scheduled to be taken out of service in 2011.

2.2.5.2 Status of Program

Established

2.2.5.3 Specifics of Program

For each station a "Distribution Station Maintenance" form will be completed. See Appendix B.

Selkirk South DS - This metal enclosed switchgear assembly will be maintained in accordance with:

- S&C Manual Metal-Enclosed Switchgear – Indoor and Outdoor Distribution (4.16 kV through 34.5 kV) – Inspection Recommendations - Data Bulletin # 620-95
- Cutler-Hammer – Instructions for Vacuum Circuit Breaker – I.B. 8295A61H04
- SEL – Power Supply/Battery Charger Instruction Manual – SEL-9310

See Appendix C for S and C manufacturer's information.

See Appendix H for Cutler-Hammer manufacturer's information.
See Appendix I for SEL manufacturer's information.

2.2.5.4 Retention of Data from Inspections

The data collected from the inspections and maintenance activities will be filed in Engineering in their respective paper folders.
In the future an MS Access database or Asset Management Software Program will be utilized to store this data.

2.2.5.5 Responsibility

Administration of Program	Operations Manager.
Administration of Deficiencies	Operations Manager.

2.2.5.6 Job Number

Job # - 08.5114.003
Title – Mtce. Dist. Stn. Equip – Maintenance Program (Primary)

2.3 Distribution System Plant Inspections and Ground Level Maintenance

2.3.1 Introduction

Distribution System Plant Inspections are regulated under the OEB Distribution System Code. The code specifies the minimum requirements to inspect urban areas on a 3 year cycle and rural areas on a 6 year cycle.

2.3.2 Status of Program

Established

2.3.3 Definition of Geographic Areas and Frequency of Program:

The areas to be utilized are the same as used in the Line Clearing Tree Trimming Maintenance Program (as described in Section 2.1) and are shown on the attached map (Appendix A).

The timing of each cycle including some completed in the past is as follows:

			Geographic Area				
Cycles	Part	Year	Urban	North	East	Central	West
1	1	2002		X			
1	2	2003			X		
1		2005	X				
1	3	2006				X	
1	4	2007					X
2		2008	X				
2	1	2009		X			
2	2	2010			X		
3		2011	X				
2	3	2012				X	
2	4	2013					X
3		2014	X				
3	1	2015	X				
3	2	2016		X			
4		2017	X				
3	3	2018				X	
3	4	2019					X

Sometimes it is not possible to perform inspections and maintenance in the entire geographic area and adjustments are made by utilizing the former township names. Where there have been minor modifications to the schedule they are noted below:

- Cycle 1 – Part 2 - 2003 – East (partial excluding Sherbrooke & Dunn)
- Cycle 1 – Part 4 – 2007 – West – Central (partial) – East (partial)

2.3.4 Specific Work to Be Completed

The specific work to be completed under this program is detailed below. The work involves a visit to each asset location. For overhead distribution plant this means every pole and for underground distribution plant this means all pad mounted equipment and street light poles.

2.3.4.1 Visual Inspection

The visual inspection is to be completed by meeting the minimum requirements of the Distribution System Code – Appendix C– Minimum Inspection Requirements. The HCHI condition of the assets will be documented by completing all required fields in the inspection database form(s). This database is built on Microsoft Access software. A copy of the input form(s) are attached in Appendix K.

2.3.4.2 Number Pole

HCHI will supply preprinted HCH asset number strips which are to be nailed or screwed to the pole on the road side 10 feet above grade. In the case of pad-mounted equipment - yellow reflective numbers will be used.

2.3.4.3 Date Nails

HCHI will provide inspection date nails which are to be nailed to the pole at eye level.

2.3.4.4 Identification Sign

HCHI public warning signs are to be nailed or screwed to the pole at approximately 6 ft high where one has not already been installed.

2.3.4.5 Global Positioning System (GPS) Coordinates

GPS coordinates will be determined and entered for each pole and pad-mount location. This information will be provided so that HCHI can download the data into HCHI's Graphic Information System (GIS). The contractor will provide all electronic equipment to perform this task.

GPS plotting will only take place in the first cycle. The program has been accelerated as follows:

- North – 2008
- East – 2009

When the second cycle begins only poles which have been installed since the last inspection cycle will need to be positioned (GPS coordinates taken).

2.3.4.6 Wood Pole Integrity Tests

Wood pole integrity tests are to be performed on poles where the strength of the pole is questionable. HCHI has determined that wood boring (1/2" bit) is the most effective way to establish the condition of the pole at or just below grade where most of the decay occurs.

2.3.4.7 Wood Pole Treatment Application

For poles that are bored and are not condemned for immediate replacement the holes are to be treated with Genics Inc. "Cobra Rod" and corresponding treated plastic plug "Cobra Plug". See Genics web site for detailed installation and application information – www.genicsinc.com.

2.3.4.8 Ground Level Repair of Defects

It has been our experience that ground level repairs can be effectively corrected during the inspection process. The contractor may make any of the following repairs as required while on site:

- Replace guy guard
- Cut unused anchors below grade and replace backfill
- Install molding over exposed down ground
- Drive exposed ground rods to below grade
- Replace ground rod clamp – remake down ground connection
- Bore pole, insert Cobra Rod, install Cobra Plug, record, and report findings

2.3.4.9 Remedial Actions to Correct Defects

This program will identify items in the field which will require replacement, repair, or alteration. See "Responsibility" below to identify the person responsible for this remedial action.

2.3.4.10 Responsibility

Administration of Program	Operations Manager.
Correction of Defects – Without I/O	Operations Manager
Correction of Defects – With I/O	Engineering Manager

I/O – Instruction Order

2.3.4.11 Job Number

Job # - 01.5020.005
Title – Ops O/H Lines – Inspection Program - Plant

2.4 Off Road High Voltage Line Inspections & Maintenance

2.4.1 Introduction – Off Road Primary

Within the boundaries of Haldimand County a number of line sections are off road and inaccessible by truck for parts of the year or at any time. All of these line sections are overhead and are located on unopened road allowances and private land. Inspection & maintenance of these lines is necessary on a regular basis to safeguard the reliability of the electrical supply.

2.4.2 Location of Specific Line Sections:

- Line Section 1 - 27kv - Townline Road East between Brookes Road and Singer Road – Poles, Conductor, Hardware
- Line Section 2 - 27kv – From Decewsville Road and Irish line to Just South of the village centre of Fisherville - Poles, Conductor, Hardware
- Line Section 3 - 27kv – From Concession 2w and Haldimand Road 53 to Concession 3 East of Haldimand Road 53 - Poles, Conductor, Hardware
- Line Section 4 - 27kv – Village of Bing to Sandy Bay Road - Poles, Conductor, Hardware
- Line Section 5 - 8kv – Canal Bank Road from Opposite Inman Road to just East of Hutchinson Road – Conductor and Supporting Hardware Only

- Line Section 6 - 27kv – 57M4 and 57M1 from Jarvis TS to Concession 3 W - Conductor and Supporting Hardware Only
- Line Section 7 - 27kv – 1st Row from 3rd Line to Haldimand Road 20 – Poles, Conductor and Supporting Hardware
- Line Section 8 – 27kv and 8kv – North Shore Drive from Opposite Municipal # 851 to Municipal # 1362 – North West of Dunnville TS – Poles Conductor and Hardware – South East of Dunnville TS – Conductor and Supporting Hardware Only.

2.4.3 Frequency and Type of Program

All sections are to be patrolled by foot or all terrain vehicle once per year
All sections are to be inspected approximately once every five years

2.4.4 Cycles

This program was initiated in 2008 and completed in 2009. This was performed in a very short time frame so that the conditions were known because no maintenance records existing from the past. In the future the cycle will be spread out to level costs associated with this program.

	Line Section							
Year	1	2	3	4	5	6	7	8
2008	X	X	X	X	X			
2009						X	X	X
2013	X	X						
2014			X	X				
2015					X	X		
2016							X	
2017								X

2.4.5 Description of Program

2.4.5.1 Patrol

A patrol consists of a visual inspection of each pole and components from the ground below the pole. Defects are noted and corrective actions put in place by Operations and/or Engineering. Field condition reports are used for reporting actions required. Information about the inspection is noted in the pole inspection database. The inspection form for "Annual Patrol – Off Road Primary" is attached as Appendix B.

2.4.5.1.1 Status of Program

Development

2.4.5.2 Inspection & Maintenance

An inspection consists of a hands on inspection of the pole and components to identify defective equipment. The inspection is to be a close inspection using a track mounted aerial device. Minor repairs are to be made on the spot – such as reframing, changing insulators, replacing guy wires, etc. Defects and actions taken are noted on the Instruction order documents and input into the pole inspection database. A sample of an instruction order is attached as Appendix J.

2.4.5.2.1 Status of Program

Established

2.4.5.3 Responsibility

Administration of Program	Operations Manager.
On the Spot Corrections	Line Crew
Correction of Defects – Without I/O	Operations Manager
Correction of Defects – With I/O	Engineering Manager

2.4.5.4 Job Number

Job # - 08.5020.005
Title – Ops. O/H Lines – Inspection Program – Off Road (Primary)

Note – Regular job numbers are used to replace equipment

2.5 Thermography Inspection Program

2.5.1 Introduction

Infrared thermography has proven to be an excellent tool to identify poor electrical connections and overloaded equipment on the distribution system. The purpose of the Thermography Inspection Program is to identify any issues and remediate them as quickly as possible to ensure continuous operation of the distribution system. This program consists of annual overhead and underground inspections of the distribution system.

2.5.2 Status of Program

Established

2.5.3 Specifics of Program

Thermography will be performed based on the parts of the distribution system emanating from the three Hydro One Transformer Stations in the County. The goal of the program

will be to inspect the entire distribution system on a three year rotational basis (excepting HCHI substations). The program involves scanning primary circuits, substations, and pad mounted electrical equipment. The priority each year will be to scan 27.6kV aerial circuits first, underground pad-mounted equipment second, and 8.3kV aerial circuits third. In 2007 no thermography was performed. The following cycle will be used:

Annually – All substations to be scanned (see Section 2.2.2 for locations)

			Transformer Stations		
Cycles	Part	Year	Dunnville TS	Jarvis TS	Caledonia TS
1	1	2008	X		
1	2	2009		X	
1	3	2010			X
2	1	2011	X		
2	2	2012		X	
2	3	2013			X
3	1	2014	X		
3	2	2015		X	
3	3	2016			X

After the scan has taken place the report will be reviewed by the Line Supervisor who will arrange repairs to any equipment noted in the report. If an extensive repair is required the Engineering Department will be notified to arrange to have an I/O produced to perform the work.

2.5.4 Retention of Data from Inspections

The thermography reports are forwarded to HCHI in pdf file format. Each year the pdf file will be placed on the corporate hard drive for storage. Remedial actions will be noted in paper format and stored in the Engineering Department.

2.5.5 Responsibility

Administration of Program	Operations Manager.
Correction of Defects – Without I/O	Line Supervisor
Correction of Defects – With I/O	Engineering Manager

2.5.6 Job Number

Job # - 01.5020.004
Title – OPS O/H Lines – Thermography

Job # - 01.5040.004
Title – OPS U/G Lines – Thermography

2.6 Switch Maintenance Program

2.6.1 Introduction

The purpose of the Switch Maintenance Program is to ensure the continued reliability of all switching devices in the electrical distribution system. The goal of the program will be to maintain all switches on a three year rotational basis. This program consists of physically cleaning, lubricating, and ensuring the switch operates smoothly. This program applies to three phase gang operated switches only (pole and pad-mounted).

There are approximately 50 overhead three phase gang operated switches and 10 pad-mounted switching cubicles installed on the system (2006 statistics).

2.6.2 Overhead Switches

2.6.2.1 Status of Program

Implemented

2.6.2.2 Frequency of Program

Approximately 16 overhead three phase gang operated switches will be maintained in each year of a 3 year cycle.

2.6.2.3 Specifics of Program

In the absence of inspection and maintenance instructions from all manufacturers HCHI will utilize A.B. Chance/Hubbell Power Systems instructions as the basis for its own step by step process. These are as follows:

- Hubbell Power Systems Inc. – Chance – P818-2040 Rev. B – Type AR Unitized, Gang-Operated Overhead Switches for Distribution Switching
- Hubbell Power Systems Inc. – Chance – P818-2040 - Installation, Operation, & Maintenance Manual for A.B. Chance Company Unitized Overhead Switchgear

See Appendix G for listing of Hubbell's manufacturer's information.

For each switch an "Overhead Switch Maintenance form will be completed. See Appendix B.

2.6.2.4 Retention of Data from Inspections

The data collected from the inspections and maintenance activities will be filed in Engineering in their respective paper folders.
In the future an MS Access database or Asset Management Software Program will be utilized to store this data.

2.6.2.5 Responsibility

Administration of Program	Operations Manager.
Schedule and Complete Work	Line Supervisor

2.6.3 Job Number

Job # - 08.5125.010
Title – Mtce. O/H Conductor - Switch Mtce Program

2.6.4 Pad-Mounted Switches

2.6.4.1 Status of Program

Implemented

2.6.4.2 Frequency of Program

Approximately 10 pad mounted switching cubicles will be maintained in each year of a 3 year cycle.

2.6.4.3 Specifics of Program

HCHI pad-mounted switches are all manufacture red by S & C Electric. Inspection and maintenance instructions are as follows:

- S&C Manual PMH Pad-Mounted Gear – (Outdoor Distribution (14.4 kV and 25 kV) – Inspection Recommendations – Instruction Sheet 662-590.

See Appendix C for listing of S&C's manufacturer's information.

For each switch a "Pad-Mounted Switch Maintenance form will be completed. See Appendix B - Forms.

2.6.4.4 Retention of Data from Inspections

The data collected from the inspections and maintenance activities will be filed in Engineering in their respective paper folders.
In the future an MS Access database or Asset Management Software Program will be utilized to store this data.

2.6.4.5 Responsibility

Administration of Program	Operations Manager.
Schedule and Complete Work	Line Supervisor

2.6.4.6 Job Number

Job # - 08.5150.010
Title – Mtce. U/G Conductor - Switch Mtce Program

2.7 Single Phase Hydraulic Recloser Maintenance

2.7.1 Introduction

The purpose of the Single Phase Hydraulic Reclosure Maintenance Program is to ensure the continued reliability of all single phase reclosure devices in the electrical distribution system. The goal of the program will be to maintain all devices on a five year rotational basis. This program consists of removing existing reclosure(s) from service, installing a new/refurbished reclosure(s) and re-conditioning the reclosers removed from service.

2.7.2 Status of Program

Implemented

2.7.3 Definition of Geographic Areas and Frequency of Program:

There are approximately 262 reclosers in service (2006 data). 204 of these are in 3 phase clusters.

Therefore, in each year of the cycle approximately 87 units will need to be maintained.

The areas are the same as used in the Line Clearing Tree Trimming Maintenance Program (as described in Section 2.1) and are shown on the attached map (Appendix A). The exception is that the urban area will not be used as there are few reclosers in the community centres. These units will be part of the rural areas for this program. The fifth year in the schedule will be used to catch up as required.

The timing of each cycle including some completed in the past is as follows:

			Geographic Areas			
Cycles	Part	Year	North	East	Central	West
1	1	2007		X		
		2008				
1	2	2009			X	
1	3	2010				X
1	4	2011	X			
2	1	2012		X		
2	2	2013			X	
2	3	2014				X
2	4	2015	X			
2		2016				
3	1	2017		X		
3	2	2018			X	
3	3	2019				X
3	4	2010	X			
3		2017				

2.7.4 Specifics of Program

The reclosers removed from the field will be returned to the service centre and kept separate from reclosers that are in inventory. Purchasing and Stores will arrange for the units to be inspected, maintained, and repaired by an authorized service company. The inspection, maintenance, and repair activities will meet or exceed Cooper Power Systems Service Information Standards as noted below:

- S280-10-9 – Types H, 4H, and V4H Maintenance Instructions dated August 2002
- S280-15-1 – Type L Recloser Maintenance Instructions dated May 2001

See Appendix D for listing of Cooper Power Systems manufacturer's information.

Defective components will be replaced at HCHI's discretion or the unit may be scrapped. As a minimum the following criteria will be used in the maintenance work:

- Un-tank internal components
- Inspect all internal components
- Re-burnish contact surfaces
- Thoroughly flush and clean internal components and tank
- Replace insulating liquid
- Replace internal liners
- Reassemble unit
- Electrically test
- Scrape, clean, prime, and repaint tank
- Stencil tank with ID

The vendor providing the maintenance service will provide a certified test report for each unit noting the results of the inspection, maintenance, repair, and testing actions. A certified test report is only valid upon certification by a Professional Engineer.

2.7.5 Responsibility

Administration of Program	Operations Manager.
Schedule and Complete Work	Line Supervisor
Arrange for Maintenance	Purchasing Clerk/Storeskeeper

2.7.6 Job Number

Job # - 08.5125.011
Title – Mtce. O/H Conductor – 1 Ph. Recloser Mtce. Program

2.8 Three Phase Recloser Maintenance

2.8.1 Introduction

The purpose of the Three Phase Reclosure Maintenance Program is to ensure the continued reliability of all three phase reclosure devices in the electrical distribution

system. The goal of the program will be to maintain all devices on a three year rotational basis. This program consists of removing existing reclosure(s) from service, installing a new/refurbished reclosure(s) and re-conditioning the reclosers removed from service.

2.8.2 Status of Program

Development

2.8.3 Frequency of Program

There are approximately 6 reclosers in service (2006 statistics). Units will be maintained every 3 years.

2.8.4 Specifics of Program

The reclosers removed from the field will be returned to the service centre and kept separate from reclosers that are in inventory. Purchasing and Stores will arrange for the units to be inspected, maintained, and repaired by an authorized service company. HCHI has two manufacturers of three phase reclosers mounted in the system being Cooper Power Systems and Joslyn Hi-Voltage.

Cooper Power Systems:

The inspection, maintenance, and repair activities will meet or exceed Cooper Power Systems Service Information Standard:

- S280-40-8 – Reclosers – Type RVE and WVE Maintenance Instructions dated September 1988

See Appendix D for listing of Cooper's manufacturer's information.

** HCHI has type WVE3815

Joslyn Hi-Voltage:

The inspection, maintenance, and repair activities will meet or exceed Joslyn Hi-Voltage Manual:

- TriMod 300 Series Manual – Installation/Operation/Service Instruction # 706-320 dated August 2002

See Appendix F for listing of Joslyn High Voltage manufacturer's information.

** HCHI has type 327-16.

Defective components will be replaced at HCHI's discretion or the unit may be scrapped.

The vendor providing the maintenance service will provide a certified test report for each unit noting the results of the inspection, maintenance, repair, and testing actions. A certified test report is only valid upon certification by a Professional Engineer.

2.8.5 Responsibility

Administration of Program	Operations Manager.
Schedule and Complete Work	Meter Supervisor

2.8.6 Job Number

Job # - 08.5125.012
Title – Mtce. O/H Conductor – 3 Ph. Recloser Mtce. Program

2.9 Line Type Step Voltage Regulator Maintenance Program

2.9.1 Introduction

The purpose of the Line Type Step Voltage Regulator Maintenance Program is to ensure the continued reliability of all regulator devices in the electrical distribution system. The goal of the program will be to maintain all devices on an as required basis. The voltage regulators in service are not serviceable on the pole and therefore, if problems arise where the regulator is not functioning properly it must be removed from service.

An improperly functioning regulator will usually exhibit the following symptoms:

- On the manual setting the taps cannot be lowered or raised through the entire range of taps;
- On the automatic setting the regulator does not regulate the voltage.

2.9.2 Status of Program

Development

2.9.3 Frequency of Program

Currently there are 2 sets of regulators in service. The maintenance and inspection program will require annual and as required intervals.

2.9.4 Specifics of Program

- Annual – Operate regulator in manual operation in each tap position and check automatic operation.
- As Required – If the regulator fails to regulate the voltage have the unit serviced by a service company providing this expertise.

The inspection, maintenance, and repair activities will meet or exceed General Electric's manufacturer's instructions as follows:

- General Electric – Type VR-1 Single Phase Step Voltage Regulators – Installation – Operation- Maintenance – Instruction GEH – 5858

See Appendix E for listing of General Electric's manufacturer's information.

2.9.5 Responsibility

Administration of Program	Operations Manager.
Schedule and Complete Work	Meter Supervisor

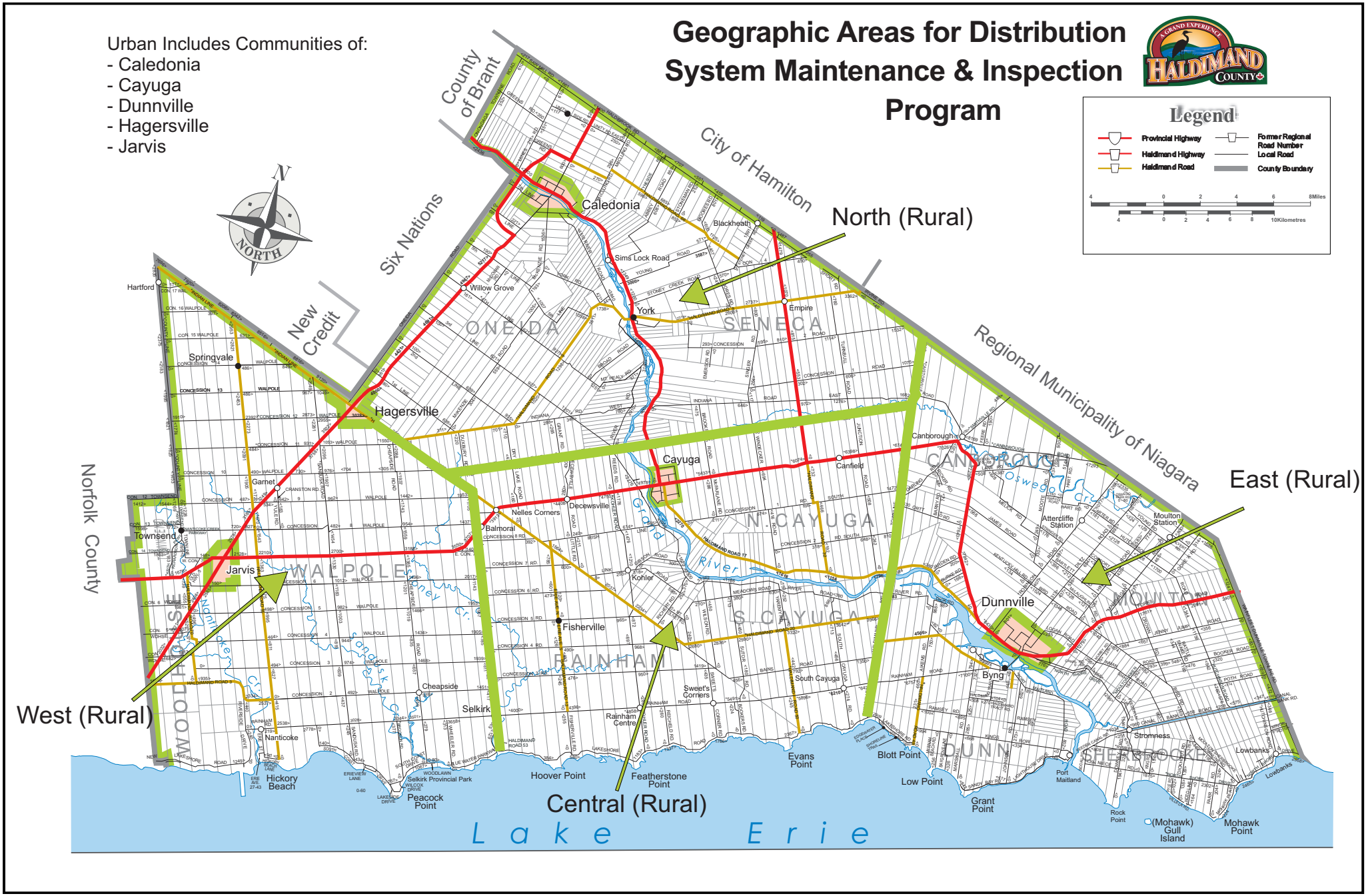
2.9.6 Job Number

Job # - 08.5125.013
Title – Mtce. O/H Conductor – 3 Ph. Regulator Mtce. Program

Appendix A - Map - Geographic Areas for Distribution System Maintenance & Inspection

Geographic Areas for Distribution System Maintenance & Inspection Program

Urban Includes Communities of:
- Caledonia
- Cayuga
- Dunnville
- Hagersville
- Jarvis



Appendix B – Maintenance Forms

- Overhead Switch Maintenance
- Pad-Mounted Switch Maintenance
- Distribution Station Maintenance
- Distribution Station Monthly Inspection – Specific to Station
- Annual Patrol – Off Road Primary

Haldimand County Hydro

DISTRIBUTION STATION MONTHLY INSPECTION

Canfield DS

Station Transformers

T1 - Ferranti-Packard - Serial # 1-3296

	Instantaneous	Peak
Temp Gauge Reading	can't reach to	reset

	High	Normal	Low	Comments
Conservator Tank Oil Level Gauge				

	Top	Radiators	Bottom Tank Valve	Other
There are Tank Oil Leaks at the following locations				

	Current	High	Low
Tap Changer Position			

Other Comments

Security - Fence Enclosure

	TRUE	FALSE
Chain Link there are No Voids or Holes in the fence		
Barbed Wire - Well Spaced and Continuous with no breaks		
Support Posts, Horizontal Rails, and Forged Hardware Sound		
Signs - One on Each Side of Enclosure & One on Gate		
Padlocks - In Place and in Working Order		
Electrical Ground(Grd) Connections - Good with no cuts or breaks		
Station Identification Sign - Visible and Readable		

Other Comments

Grounds

	TRUE	FALSE	Comments
Weed Growth is Acceptable			
Trees Clear of Electrical Contact			
Regular Grass Cutting is Apparent			
Clear of Debris			

Structures

Steel Structure

	TRUE	FALSE	Comments
Electrical Ground Connections - Good			
Steel in Good Condition			
No Broken Insulators			

Wood Structure

	TRUE	FALSE	Comments
Timber Good			
Pole(s) Good			
Anchors Good			

Haldimand County Hydro

DISTRIBUTION STATION MONTHLY INSPECTION

Canfield DS

Spare Fuses			
	TRUE	FALSE	Comments
There are Spare HV Fuses on site			
Potential Transformers			
	TRUE	FALSE	Comments
There are no Visible Oil Leaks			
Reclosures			
	TRUE	FALSE	Comments
There are no Visible Oil Leaks			
There are no Signs of Overheating			

Date Inspected _____

Inspected By _____

Shading indicates that a corrective action is required

Action Items:

By Who	Action Required	Date Completed

Haldimand County Hydro Inc.
Maintenance and Inspection Program
Distribution Station Maintenance

Station Name: _____
Location: _____

AS FOUND CONDITION

Using the check boxes indicate the condition of the station when you first arrive. Note - a check indicates you agree with the statement. If you don't agree leave the box unchecked.

Switches – Utilize Switch Maintenance Overhead Form

Transformer

- Bushing Condition (crack, break, burn free)---------- ☐
- Current Oil Leaks – No signs of dripping oil---------- ☐
- Old Oil Leaks – No signs of old leaks---------- ☐
- Main Tank – No signs of advanced corrosion or pending failure of case------ ☐
- Gaskets – No signs of gasket failure---------- ☐
- Grounding – All grounding in place & connections solid---------- ☐
- Concrete Foundation – No deterioration of concrete---------- ☐
- Electrical Connections – No signs of poor connections---------- ☐

Steel or Wood Structure Including Current Carrying Parts

- Insulator Condition (crack, break, burn free)---------- ☐
- Grounding – All grounding in place & connections solid---------- ☐
- Concrete Foundation – No deterioration of concrete---------- ☐
- Electrical Connections – No signs of poor connections---------- ☐

Metering Equipment

- Insulator Condition (crack, break, burn free)---------- ☐
- Grounding – All grounding in place & connections solid---------- ☐
- Electrical Connections – No signs of poor connections---------- ☐

Fence

- Grounding – All grounding in place & connections solid---------- ☐

Grading

- Stone is high enough to eliminate gaps under fence---------- ☐

MAINTENANCE PERFORMED

Transformer – Not Req'd ☐ Or _____

_____

_____

Steel or Wood Structure Including Current Carrying Parts – Not Req'd ☐ Or

_____

_____

Meter Equipment – Not Req'd ☐ Or _____

_____

Fence – Not Req'd ☐ Or _____

_____

_____

Grading – Not Req'd ☐ Or _____

_____

Comments - _____

_____

_____

Future Work - Note any item which requires future work or design - _____

_____

_____

_____

OPTIMIZATION OF MAINTENANCE PROGRAM

Indicate which one of the following statements applies to this particular station:

☐ A The maintenance was unnecessary; it could have been done later
☐ B The maintenance was performed at the right time; only normal maintenance was req'd
☐ C The maintenance should have been done earlier; major faults were found

Lead Hand: _____ Date Work Completed: _____

Maintenance Procedure

Note – Standard visual inspection procedures are not noted but are expected to be completed. Items listed below are actual hands on tasks.

Transformer

Step 1

Check bushing connections to make sure they are tight

Step 2

Where there is a suspected or actual oil leak and a gasket is suspected attempt to tighten bolts pressuring the gasket.

Steel or Wood Structure Including Current Carrying Parts

Step 1

On all current carrying components make sure they are tight

Step 2

Putting pressure on all insulators to make sure they have not cracked and separated into more than one piece.

Haldimand County Hydro Inc.
Maintenance and Inspection Program
Pad-Mounted Switch Maintenance

Switch Number: _____
Location: _____

AS FOUND CONDITION

Using the check boxes indicate the condition of the switch when you first arrive. Note - a check indicates you agree with the statement. If you don't agree leave the box unchecked.

Switch(s) –open and closes freely---------- ☐
Contacts are clean, aligned, and free from corrosion---------- ☐
Moving parts operate freely (switch and operating handle)---------- ☐
Insulators are crack, break, and burn free---------- ---------- ☐
Interior is clean---------- ☐
Exterior does not have corroded parts and painting is not required---------- ☐

MAINTENANCE PERFORMED

Inspect and Clean Interior – Not Req'd ☐ Or _____

_____

Inspect Barriers and Minimum Air Clearances – Not Req'd ☐ Or _____

_____

Inspect and Exercise Mini Rupter Switches – Not Req'd ☐ Or _____

_____

Inspect Fuses – Not Req'd ☐ Or _____

_____

Inspect Key Interlock and Door Latching Mechanisms – Not Req'd ☐ Or

_____

_____

Touch up Exterior – Not Req'd ☐ Or _____

_____

Comments - _____

_____

_____

OPTIMIZATION OF MAINTENANCE PROGRAM

Indicate which one of the following statements applies to this particular switch:

☐ A The maintenance was unnecessary; it could have been done later
☐ B The maintenance was performed at the right time; only normal maintenance was req'd
☐ C The maintenance should have been done earlier; major faults were found

Lead Hand: _____ Date Work Completed: _____

Inspection and Maintenance Procedure

Refer to S&C Manual PMH Pad-Mounted Gear – (Outdoor Distribution (14.4 kv and 25 kv) – Inspection Recommendations – Instruction Sheet 662-590

Haldimand County Hydro Inc.
Maintenance and Inspection Program
Overhead Switch Maintenance

Switch Number: _____
Location: _____

AS FOUND CONDITION

Using the check boxes indicate the condition of the switch when you first arrive. Note - a check indicates you agree with the statement. If you don't agree leave the box unchecked.

Switch –open and closes freely---------- ☐
Interrupters or arc chutes operate freely---------- ☐
Contacts are clean, aligned, and free from corrosion---------- ☐
Moving parts operate freely (switch and operating handle)---------- ☐
Mounting hardware is tight and free of defects---------- ☐
Insulators are crack, break, and burn free---------- ---------- ☐
Electrical contacts and conductors to main line are tight and corrosion free------- ☐

MAINTENANCE PERFORMED

Switch Movement – Not Req'd ☐ Or _____

_____

Mounting Hardware – Not Req'd ☐ Or _____

_____

Switch Components – Not Req'd ☐ Or _____

_____

Interrupters – Not Req'd ☐ Or _____

_____

Comments - _____

_____

_____

OPTIMIZATION OF MAINTENANCE PROGRAM

Indicate which one of the following statements applies to this particular switch:

☐ A The maintenance was unnecessary; it could have been done later
☐ B The maintenance was performed at the right time; only normal maintenance was req'd
☐ C The maintenance should have been done earlier; major faults were found

Lead Hand: _____ Date Work Completed: _____

Inspection and Maintenance Procedure

Step 1 – Pre-Check Before Operating Switch

Insulators – check all insulators for cracks, breaks, or burns

Power Conductors – be sure all conductors are routed so they don't interfere with switch operation

Mounting Hardware – check and tighten all thru bolts and mounting hardware. Inspect all pins, rivets, and bolted connections for damaged and worn out parts.

Step 2 – Cycle Switch

Open and close switch several times to clean the contact surfaces and loosen moving parts. Make sure interrupters or arc chutes are operating freely.

Step 3 – Check Switching Sequence

Inspect the switch for proper operating sequence.

Step 4 – Inspect Switch Components

Inspect for eroded fault making contacts
Inspect for alignment and corrosion of "live parts"
Lubricate all contacts with Dow Corning FS-1292 silicone grease or equivalent

Step 5 – Inspect Moving Parts

Inspect all interphase and moving parts for damaged or worn out components
Lubricate as needed all control components with A.B. Chance silicone spray Cat. #C400-1749 or equivalent

Step 6 – Inspect Interrupter or Arc Chutes

Make sure interrupters or arc chutes are operating freely

Notes

Replace any damaged or worn parts as required

Haldimand County Hydro Inc. Maintenance Inspection Program
Annual Patrol - Off Road Primary

Off Road Line Section Number:	
Date Inspected:	
Inspectors Name:	

Instructions: Write pole number in column and check each category where there are no corrective actions required.

Pole Number	Pole	Pole Hdwe	Insulators	Pole Mounted Equipment	Incumberances	Guying	Signage	Corrective Actions to Take Place

Appendix C – S&C Reference Material

Reference # 1 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Inspection Recommendations – Instruction Sheet 662-590

Reference #2 – S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Specifications - Specification Bulletin 662A-31

Reference # 3 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Instructions for Installation - Instruction Sheet 662-505

Reference # 4 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Instructions for Operation - Instruction Sheet 662-510

Reference # 5 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Descriptive Bulletin 662-30

Reference # 6 - S&C Manual Metal-Enclosed Switchgear (Indoor and Outdoor Distribution (4.16 kV through 34.5 kV)) – Inspection Recommendations – Data Bulletin 620-95

Reference #7 – S&C Alduti-Rupter Switches – Outdoor Distribution (14.4kV through 69kV) – Descriptive Bulletin

Reference #8 – S&C Alduti-Rupter Switches – Outdoor Distribution (14.4kV through 46kV) – Specification Bulletin – 761-31

Reference #9 – S&C Alduti-Rupter Switches – Outdoor Distribution – Addendum to Instruction Sheets 761-5XX – 761-31 – Instruction Sheet 761-500A

Reference #10 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Double-Break Style Rotating Operating Mechanism – 35.5kV and 47kV – Instructions for Installation and Operation - Instruction Sheet 761-500

Reference #11 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Vertical-Break Integer Style Tiered-Outboard Mounting Configuration – 25/34.5kV and 34.5kV – Instructions for Installation - Instruction Sheet 761-530 – HCHI Stock Code 681910

Reference #12 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Side-Break Integer Style Rotating Operating Mechanism – 25/34.5kV and 34.5kV – Instructions for Installation and Operation- Instruction Sheet 761-580 – HCHI Stock Code 681905

Reference #13 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Vertical-Break Integer Style – 25/34.5kV and 34.5kV – Instructions for Installation - Instruction Sheet 761-535 – HCHI Stock Code 681900

Appendix D – Cooper Power Systems Reference Material

Reference # 1 - S280-40-8 – Reclosers – Type RVE and WVE Maintenance Instructions dated September 1988

Reference # 2 - S280-40-2 – Reclosers Types VWE, VWVE27, VWVE38X, WE,WVE27, and WVE38X – Three Phase Electronically Controlled – Installation and Operation Instructions dated March 2003

Reference # 3 – Cooper Power Systems Reclosers – Types H, 4H, and V4H Maintenance Instructions – Service Information S280-10-9

Reference # 4 – Cooper Power Systems Reclosers – Type L Maintenance Instructions – Service Information S280-15-1

Reference # 5 – Cooper Power Systems Reclosers – Type H Single Phase Maintenance Instructions – Service Information S280-10-1

Reference # 6 – Cooper Power Systems Reclosers – Type D, DV Single Phase Maintenance Instructions – Service Information S280-20-2

Reference # 7 – Cooper Power Systems Reclosers – Type 4H Single Phase Oil Circuit Recloser Equipment Specifications

Reference # 8 – Cooper Power Systems Reclosers – Type L Single Phase Oil Circuit Recloser Equipment Specifications

Appendix E – General Electric Reference Material

Reference # 1 - General Electric – Type VR-1 Single Phase Step Voltage Regulators – Installation – Operation- Maintenance – Instruction GEH - 5858

Appendix F – Joslyn Hi-Voltage Reference Material

Reference # 1 - TriMod 300 Series Manual – Installation/Operation/Service Instruction # 706-320 dated August 2002

Appendix G – Hubbell Power Systems Inc. Reference Material

Reference # 1 - Hubbell Power Systems Inc. – Chance – P818-2040 Rev. B – Type AR Unitized, Gang-Operated Overhead Switches for Distribution Switching

Reference # 2 - Hubbell Power Systems Inc. – Chance – P818-2040 - Installation, Operation, & Maintenance Manual for A.B. Chance Company Unitized Overhead Switchgear

Appendix H – Cutler-Hammer Reference Material

Reference # 1 – Cutler-Hammer – Instructions for the Use, Operation and Maintenance of the Red Line Type VCP-WR Vacuum Circuit Breaker Elements – I.B. 8295A61H04

Appendix I – SEL Reference Material

Reference # 1 – SEL Power Supply/Battery Charger Instruction Manual – SEL-9310

Appendix J – Sample of Instruction Order for Off Road Inspections

Haldimand County Hydro Inc.
Instruction Order
Date

For – Crew

Job Numbers

Maintenance – Poles/Towers/Fixtures

- Job # - 01-5120-005 – Use for general inspection time
- Job # - 01-5120-001 - Use for all material replacements (x-arms, braces, insulators, pins)

Maintenance – Overhead Conductor and Devices

- Job # - 01-5125-001 – Use for replacing devices (switches, arresters, jumpers, etc.)

Tree Trimming and Line Clearing - Job # - 01-5135-001

Job Locations

The following job locations are in order of priority and sequence:

- 1st Row Between 3rd Line and Haldimand Road 20 - Poles, Conductor and Hardware
- North Shore Drive from Opposite Municipal # 851 to Municipal # 1362 – North West of Dunnville TS – Poles, Conductor and Hardware – South East of Dunnville TS – Conductor and Supporting Hardware Only.

Work To Be Completed

General Notes:

- All of these pole lines are off road and are not normally accessible with truck equipment.
- Make your own arrangements with land owners before entering private properties
- Some lines are on unopened public road allowances – no permission is required here

Work:

- Inspect all conductor supports and insulation. Defective equipment is to be replaced. Defective wood cross arms to be replace with armless construction utilizing standard framing. If the x-arm is in good condition only replace pins, braces, and insulators as required.
- Report any defective poles – I/O's will be issued for these and likely we will replace these as we go.
- Inspect and replace defective guying and anchoring.
- If changes to a pole require a different standard than enclosed confirm which engineering standard to use with office before proceeding.
- Clear any trees or branches interfering with lines

Information to be Logged

Make notes about any work completed or needing to be completed on the drawings supplied.

Appendix K – Sample of HCH Inspection Report

Haldimand County Hydro Inspection Report

Service Order	☑	Year Completed	2007	Record ID	444

Asset Number:	003547
Poles	0
Direction Of	
911 Numbe	524
Street Name	ALDER ST
Area	Dunnville
Street Light #	H122268
Tx Number	0
Switch #	
Recloser #	
Capacitor #	
Voltage Regulator #	
PMU #	
Pole Material	
Pole Year	
Pole Ownership	
Primary Circuit 1	
Primary Circuit 2	
Primary Circuit 3	
Secondary Circuit 1	
Secondary Circuit 2	
Secondary Circuit 3	
Streetlight Wire	No
Attachment 1	
Ground Rod	No
Arrestors	No

INSPECTOR'S REPORT

Priority	High
Pole Condition	Okay
Pole Test Results:	
Pole Treated	☐
X-Arm	Okay
Insulators	Okay
Arrestor	Okay
Switch	Okay
Grounding	Okay
Guying	Okay
Guard Required	Yes
Hazards	Clearances
Warning Sign	
Access Difficult	
Nomenclature	
Locks	
Lift Bolts	
Base	
Appearance	
Customer Owned	No
ESA Required	☐
ESA Advised Date:	

Duplicate Record

Comments	**Secondary Clearance over the Bell - Clearance measured at 3.5' - Minimum Okay**

Hazard Report:	No hazard present and no follow up required	**Date:**	9/6/2007	**Inspector**	S.D.

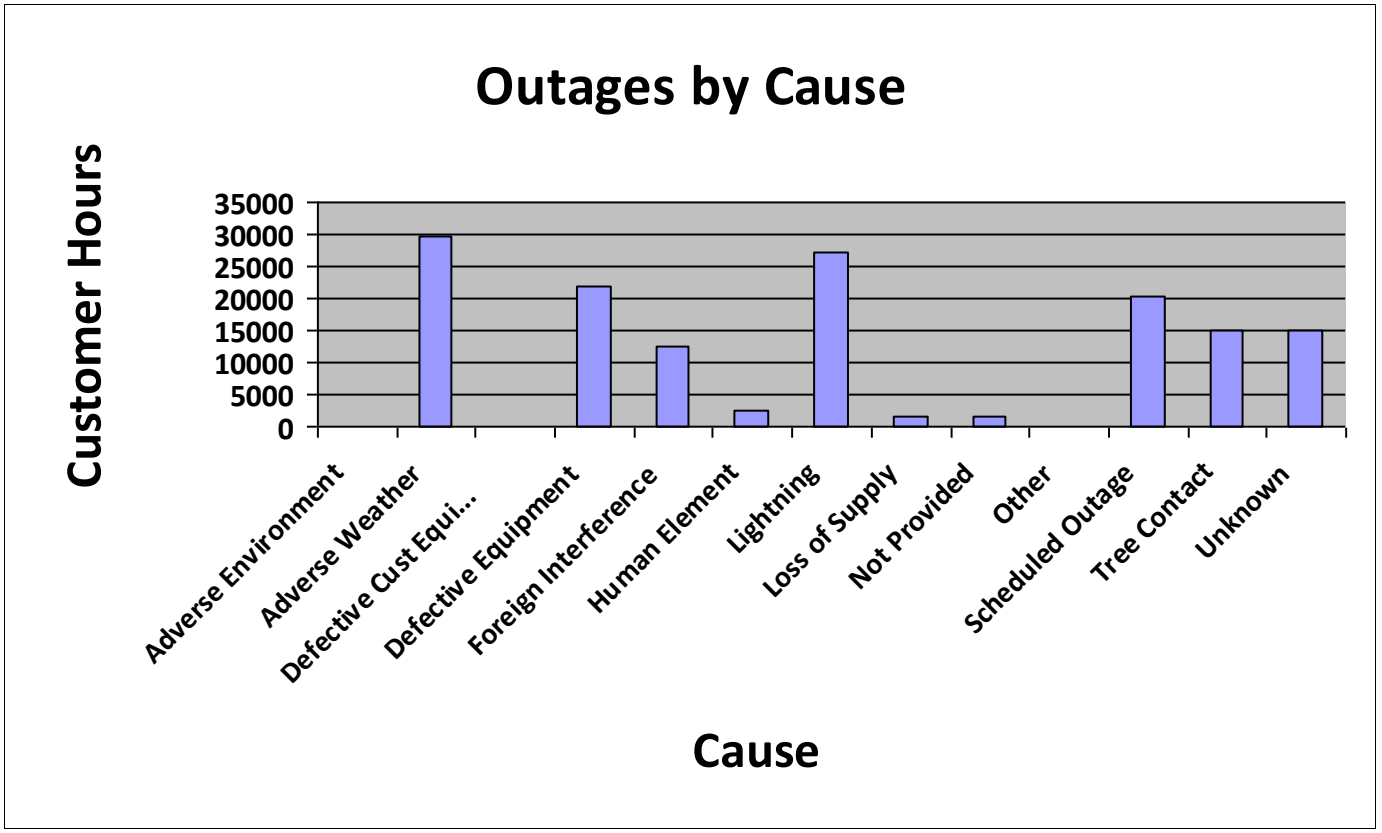
Appendix D – Service Reliability Indices by All Circuits – 2008

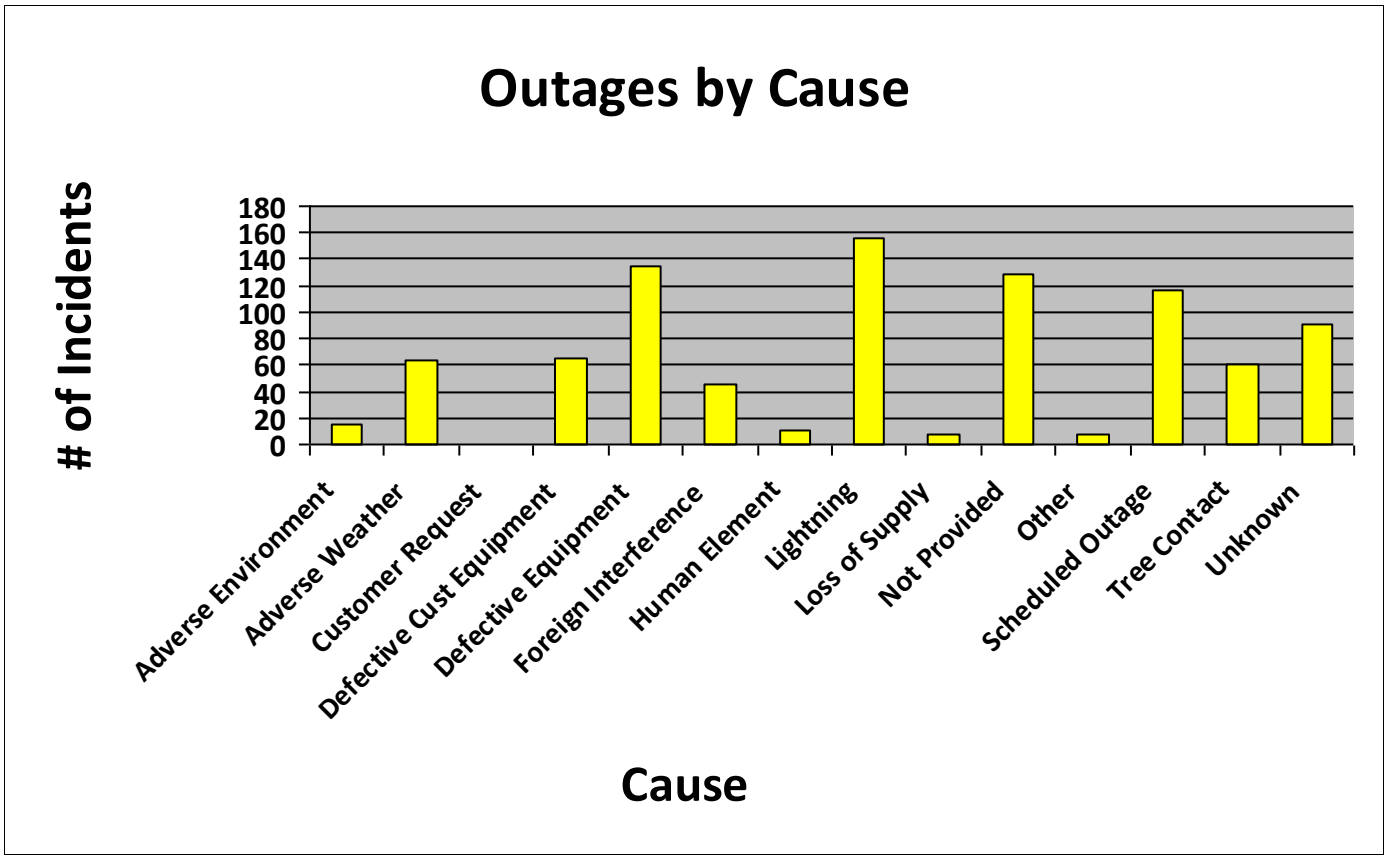
Service Reliability Indices by All Circuits

Circuit	Total Cust Hours of Interruptions (1)	Total Cust Interruptions (2)	Total Number of Customers (3)	SAIDI Average Hours of Interruptions /Cust (4) = (1) / (3)	SAIFI Average # of Interruptions /Cust (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Jarvis F1	620.77	272	228	2.722675	1.192982	2.282243
Argyle F2	887.67	452	195	4.552154	2.317949	1.963872
Canfield F1	15,647.85	5898	436	35.889564	13.527523	2.653077
Canfield F2	703.00	495	315	2.231746	1.571429	1.420202
Canfield F3	15.28	7	286	0.053427	0.024476	2.182832
Decewsville F2	5,479.92	1901	265	20.678943	7.173585	2.882651
Decewsville F3	737.37	259	290	2.542655	0.893103	2.846990
Argyle F1	89.50	46	464	0.192888	0.099138	1.945652
Dunnville F3	3,164.23	548	741	4.270216	0.739541	5.774144
Selkirk F4	331.42	109	502	0.660199	0.217131	3.040556
Jarvis F3	578.86	145	427	1.355644	0.339578	3.992143
Lythmore F1	283.95	72	392	0.724362	0.183673	3.943759
Lythmore F2	8.00	4	40	0.200000	0.100000	2.000000
Lythmore F3	8.50	3	141	0.060284	0.021277	2.833294
Nanticoke	3,743.66	697	647	5.786182	1.077280	5.371103
Selkirk F1	2,750.14	998	632	4.351487	1.579114	2.755651
Selkirk F3	8,628.00	2876	346	24.936416	8.312139	3.000000
Dunnville F1	1,547.27	286	523	2.958451	0.546845	5.410036

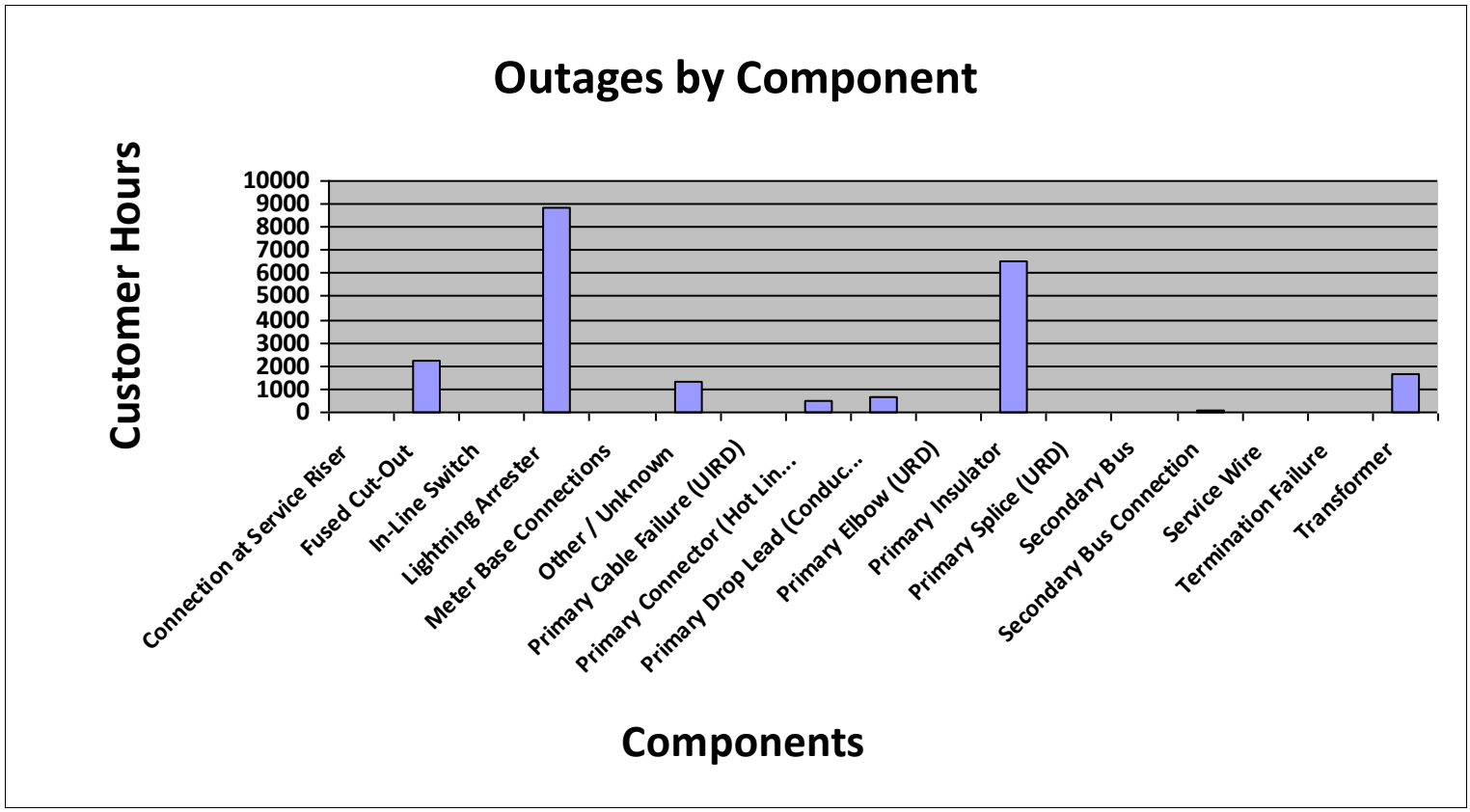
57M6 Jarvis	26,472.99	8083	2830	9.354413	2.856184	3.275144
57M4 Jarvis	1,541.50	264	990	1.557071	0.266667	5.839009
57M3 Jarvis	1,422.12	887	4895	0.290525	0.181205	1.603295
31M2 Dunnville	34,466.03	12043	1604	21.487550	7.508105	2.861914
31M1 Dunnville	7,048.67	2601	3027	2.328599	0.859267	2.709983
27M6	1,331.75	1112	2696	0.493973	0.412463	1.197618
27M5	481.16	194	1645	0.292498	0.117933	2.480205
27M4	23,202.24	10774	2249	10.316692	4.790574	2.153540
27M3	5,536.16	3358	1626	3.404772	2.065191	1.648648

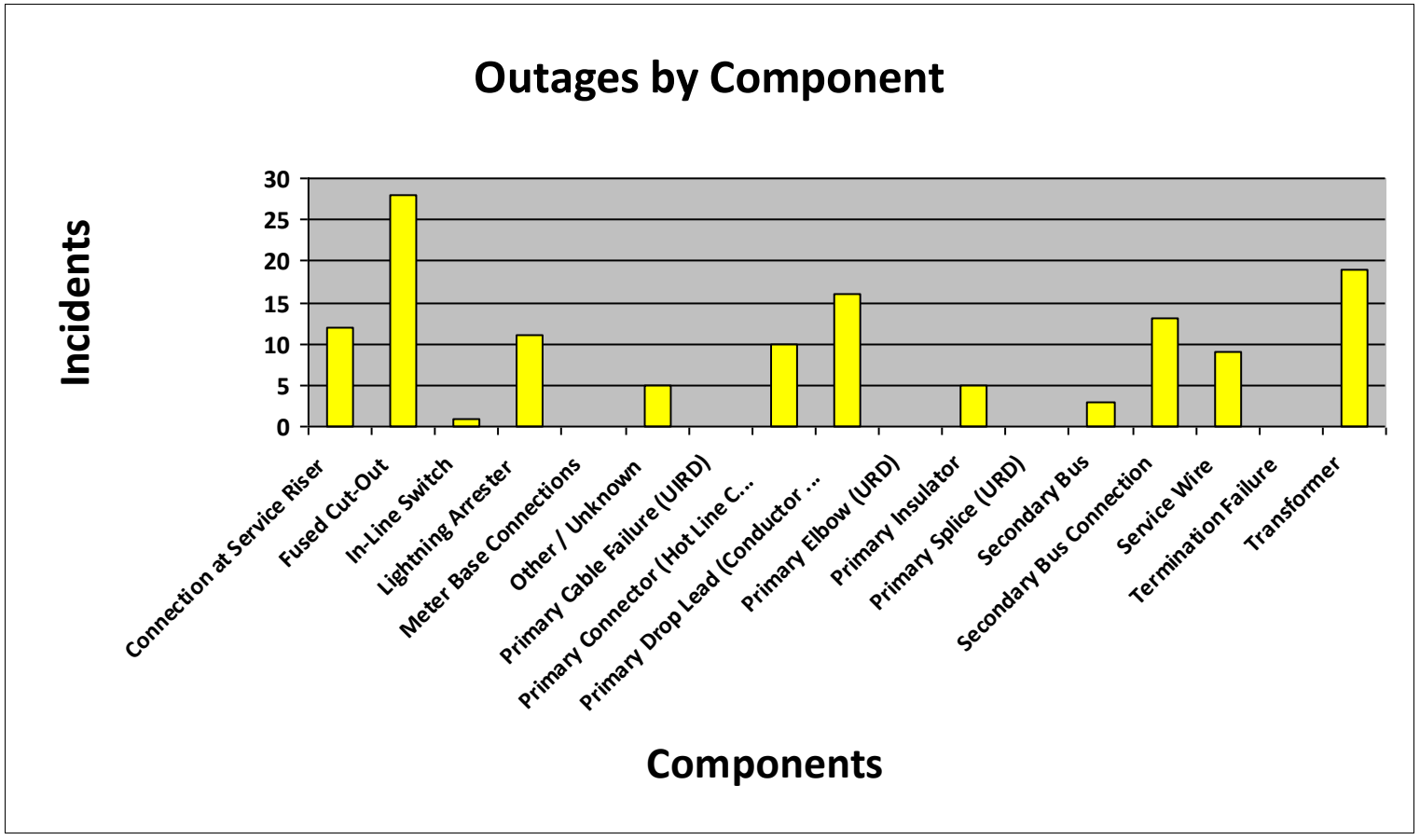
Appendix E - Outages by Cause for 2008


Outages by Cause
Customer Hours
35000
30000
25000
20000
15000
10000
5000
0
Adverse Environment
Adverse Weather
Defective Cust Equi...
Defective Equipment
Foreign Interference
Human Element
Lightning
Loss of Supply
Not Provided
Other
Scheduled Outage
Tree Contact
Unknown
Cause


Outages by Cause
# of Incidents
180
160
140
120
100
80
60
40
20
0
Adverse Environment
Adverse Weather
Customer Request
Defective Cust Equipment
Defective Equipment
Foreign Interference
Human Element
Lightning
Loss of Supply
Not Provided
Other
Scheduled Outage
Tree Contact
Unknown
Cause

Appendix F - Outages by Component for 2008


Outages by Component
Customer Hours
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Connection at Service Riser
Fused Cut-Out
In-Line Switch
Lightning Arrester
Meter Base Connections
Other / Unknown
Primary Cable Failure (URD)
Primary Connector (Hot Lin...
Primary Drop Lead (Conduc...
Primary Elbow (URD)
Primary Insulator
Primary Splice (URD)
Secondary Bus
Secondary Bus Connection
Service Wire
Termination Failure
Transformer
Components


Outages by Component
Incidents
30
25
20
15
10
5
0
Connection at Service Riser
Fused Cut-Out
In-Line Switch
Lightning Arrester
Meter Base Connections
Other / Unknown
Primary Cable Failure (URD)
Primary Connector (Hot Line C...
Primary Drop Lead (Conductor ...
Primary Elbow (URD)
Primary Insulator
Primary Splice (URD)
Secondary Bus
Secondary Bus Connection
Service Wire
Termination Failure
Transformer
Components

Appendix G – Distribution Asset Condition Assessment for Haldimand County Hydro Inc. – Kinectrics Inc. Report No. – K-014704-RA-0001-R02

DISTRIBUTION ASSET CONDITION ASSESSMENT
FOR
Haldimand County Hydro Inc.

Kinectrics Inc. Report No.: K-014704-RA-0001-R02

Confidential & Proprietary Information
Contents of this report shall not be disclosed
Without authority of client.
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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Haldimand County Hydro Inc.

@Kinectrics Inc., 2009.

DISTRIBUTION ASSET CONDITION ASSESSMENT
FOR
Haldimand County Hydro Inc.

Kinectrics Inc. Report No.: K-014704-RA-0001-R02

March 10, 2009

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REVISION HISTORY

Revision Number	Date	Comments	Approved
R00	January 22, 2009	Original Draft	
R01	February 20, 2009	"Final Draft"	
R02	March 10, 2009	Final	

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1 EXECUTIVE SUMMARY

1.1 About the Project

Haldimand County Hydro Inc. (HCHI) retained Kinectrics Inc. (Kinectrics) to perform the following tasks:

1. Carry out an Asset Condition Assessment (ACA) of the HCHI's distribution assets divided into 10 Asset Groups (these groups and overall Health Indices (HI) for each are shown in the Section 1.4 below).
2. Carry out a Risk Assessment for the Asset Groups with Sufficient Amount of Information.
3. Provide prioritized recommendations to close data gaps.
4. Recommend Capital Replacements Plan (CRP) for the next 20 years
5. Review HCHI's maintenance practices.
6. Develop methodology for prioritizing "discretional" capital projects.

This report summarizes tasks 1 through 5 and the results for task 6 are presented in a separate report.

1.2 Information Availability and Health Index Methodology Used

Sufficient information was available for most of the distribution station transformers (Group A) and about half of the pole population (Group F). Health Index and age distribution for all the poles were then extrapolated from the known age information since it was considered to be representative of the total poles population. The Health Index derivation methodology described in Appendix I and II was used for these two Asset Groups.

The remaining Asset Groups, with the exception of the gang-operated switches that had infrared testing data available for several units, had only age information available for some of the assets. Where age information was available only for some of the assets, age distribution for the remaining assets in these Asset Group was extrapolated assuming that the known data are representative of the whole population. Age was then used to estimate their Health Index distribution based on the typical age-based industry experience.

The Data Availability Indicator (DAI) for assessing the percentage of data available as compared to the ideal data set was calculated for Groups A and F only. For the remaining Asset Groups, the percentages of the assets with known age were provided.

Based on the data availability, a prioritized strategy for closing data gaps was provided for all the Asset Groups.

The results were then modified, where possible, based on the expert opinion of the HCHI staff and one-day of field observations conducted jointly by Kinectrics and HCHI staff.

1.3 Health Index Results Summary

Table 1-3 below shows an overall HI for each of the 10 Asset Groups. The HI is shown as a percentage assuming that "as new" condition is 100%. The table also shows number of assets in each Asset Group and indicates how HI was derived.

Table 1-3 Health Index Summary

Asset Group	Description	# of Assets	Asset Group Overall HI,%	Methodology
A	Distribution Station Transformers	11	71%	HI Methodology (Appendix I) PLUS Expert Opinion
B	Air Blast Circuit Breakers	2	100%	Age Only
C	Pole Mounted Transformers	≈ 6,120	74%	Age Only
D	Pad Mounted Transformers	≈ 460	92%	Age Only
E	Vault Room Transformers	3	70%	Age Only
F	Poles	≈ 27,000	69%	HI Methodology (Appendix II) PLUS Expert Opinion
G	Gang Operated Overhead Switches	46	83%	Age Only PLUS Expert Opinion and IR Tests
H	Pad Mounted Switchgear	10	84%	Age Only PLUS Field Observations
I	Underground XLPE Cable	28 Feeders (81 km)	89%	Age Only
J	Overhead Reclosers	7	67%	Age Only PLUS Expert Opinion

Appendix III shows HI results along with age distribution for all Asset Groups as well as DAI for Asset Groups A and F and percentage of assets with available age for the remaining Asset Groups.

1.4 Capital Replacements Plan (CRP)

CRP consists of two components: 1) number of units that need to be replaced and 2) the corresponding replacements cost.

The number of units to be replaced was estimated for different Asset Groups based on the replacement approach where the *proactive* approach aims to replace assets before they fail and the *reactive* approach after they fail:

- For the Asset Groups with the *proactive* replacement approach, specific units or a number of units within the total population were identified for replacements based on their calculated HI, expert opinion or field observations.
- For the Asset Groups with the *reactive* replacement approach, a number of units that are expected to fail were estimated based on comparing their age distribution with the industry-based probability failure curves. A new lower failure rate was assumed for the replaced assets.

The Capital Replacement Cost for each Asset Group was then calculated assuming 2% discount rate and using replacement values: either provided by HCHI or provided by Kinectrics based on the typical industry data. These values and the replacement approach used are shown in the Table 1-4 below.

Table 1-4 Capital Replacements Plan Summary

Group	Description	Replacement Cost	CRP Approach
A	Distribution Station Transformers	$300,000	Proactive
B	Air Blast Circuit Breakers	$30,000	Proactive
C	Pole Mounted Transformers	$3,700	Reactive
D	Pad Mounted Transformers	$7,000	Reactive
E	Vault Room Transformers	$12,500	Reactive
F	Poles	$3,500	Proactive
G	Gang Operated Overhead Switches	$13,000	Proactive
H	Pad Mounted Switchgear	$30,000	Reactive
I	Underground XLPE Cable	$200/m	Reactive
J	Overhead Reclosers	$21,500	Proactive

Both components of the CRP, number of units to be replaced and corresponding cost, are shown in Appendix III for each of the Asset Groups.

The overall CRP is shown in Section 6.3 of this report. Furthermore, some of the *proactive* replacements could be deferred in order to levelize capital cost requirements over time provided it does not significantly increase failure risk. The levelized CRP is also shown in Section 6.3 of this report.

1.5 HCHI Maintenance Practices

The Distribution System Code provides guidance on recommended maintenance practices for LDCs. Generally, the requirements are that a distributor shall maintain its distribution system in accordance with:

- Good utility practices.
- More frequent inspections if warranted due to local conditions.
- The use of qualified persons.
- Inspection cycles structured in a manner in which defects identified during inspection activities are to be repaired in accordance with good utility practice.
- Address defects discovered within a reasonable period of time.

- Notification of customers regarding the expected duration and frequency of planned outages

HCHI's practice in this area appears to be compliant with the intent of the OEB's DSC guidelines. Though not fully developed, HCHI's inspection and maintenance plan is based on a solid grasp of priorities in the area of system maintenance. HCHI is ramping up its inspection and maintenance regimen in a manner that follows good utility practice. Furthermore, HCHI's maintenance program is well suited to the specific geography and layout of its distribution system.

1.6 Conclusions

1. Generally, HCHI's assets are in a "Good" condition based on the available information, expert opinion and one-day field observations. A concentrated effort for the following Asset Groups is required:
    - About 300 poles/year need to be replaced over the next 20 years to replace the poles found to be close to failure based on the results of the pole inspection program and expected to deteriorate to similar condition in the future years.
    - Two distribution station transformers, AT9442 and 1-3296, should be replaced over the next couple of years. Note, however, that both these transformers are missing age data, had a low data availability index and they have a lowered health index when oil quality (a maintainable condition) is removed from the calculation, so the need for replacement may be re-assessed if a more complete data becomes available witin the next year.
    - 3 Joselyn Reclosers need to be replaced over the next couple of years
    - A periodic preventative maintenance program for the Air Blast breakers is required to ensure that their condition is monitored at a regular intervals

2. Although the data availability was comparable with utilities of similar size, there is a need to close data gaps for some of the assets, particularly for Poles, Station Breakers and Underground Cables, as well as to continue and enhance data gathering for Distribution Station Transformers.

3. HCHI's maintenance practices, particularly since there is a plan to further develop inspection and maintenance programs, are compliant with the DSC requirements and are well suited for the geographical area served by this LDC.

2 INTRODUCTION

Haldimand County Hydro Inc. (HCHI) is an Ontario Local Distribution Company located in Haldimand County along the shore of Lake Erie encompassing the community centers of Caledonia, Cayuga, Hagersville, Jarvis and Dunnville. HCHI serves just over 20,000 customers in both urban and rural settings covering an area of 1,252 km^2 (320,753 acres) with 1,706 km of distribution line length. The service territory of HCHI includes urban areas typical of most towns and cities, rural areas typical of most farmland, and cottage areas.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and components and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

HCHI retained the services of Kinectrics to perform an asset condition assessment of its electrical distribution system, estimate the resultant capital replacement requirement, and to provide a methodology for prioritizing projects aimed at system expansion or enhancement.

This report presents the findings of the review of HCHI's distribution assets and includes the development of Health Indices for the specified asset categories, Risk Assessment based on probability of failure and criticality assessments and recommendation of an Asset Sustainability Plan (Replacements). Prioritization Methodology for evaluating capital projects other than end-of-life replacements is presented in a separate report.

A considerable portion of this work was devoted to the development of Health Indices based on the sometimes very limited information available and a brief visual field survey conducted by Kinectrics. The report presents the Health indices derived for the asset classes and the capital plan required for prudent replacement of assets at end of life.

2.1 Objective

The scope of work covered the following distribution system assets referred to as Asset Groups throughout this report: (the total population for each Asset Group is shown in brackets):

A. Distribution Station Transformers (11)
B. Distribution Station Circuit Breakers (2)
C. Pole Mounted Transformers (about 6,120)
D. Pad Mounted Transformers (460)
E. Vault/Transformer Room Transformers (2)
F. Poles – Wood, Concrete, Steel (about 27,000)
G. Gang Operated Overhead Switches (70)
H. Pad Mounted Switchgear (10)
I. Primary Underground XLPE Cable (about 81 circuit km and 28 feeders)
J. Three Phase Overhead Reclosers (7)

2.2 Scope of the Work

The scope of work was to include the following for the above Asset Groups:

A. Condition Assessment of electrical distribution assets;
B. Provide detailed summary of best practices within the electrical utility and general industry business sector on the asset deterioration process, failure modes, consequences of failure, and end of life criteria;
C. Collect available asset attributes and condition data from HCHI's records
D. Extrapolate, using statistically relevant protocols, number and condition of assets for which required data/information has not yet been collected;
E. Provide a replacement schedule for a twenty year replacement period for all the assets based on the asset condition assessment analysis;
F. Conduct a sampling survey/audit to verify accuracy of information on assets contained in the HCHI's records and report findings;
G. Review the adequacy of HCHI's inspection and maintenance programs and provide recommendations for improvements;
H. Review the adequacy of HCHI's record keeping systems/processes and provide recommendations;
I. Develop Health Indices for all distribution asset categories

2.3 Deliverables

The deliverable is a report that is to include the following information:

- Short description of the asset groups being considered in the study
- Demographics of the assets being considered
- Discussion on asset degradation and end-of-life issues
- Health Index results for the assets with available data
- Recommended strategy for closing information gaps
- Description of the methodology for assessment of criticality and consequence of failure of assets
- Risk Assessment results based on probability of failure and criticality assessment
- Recommended Asset Sustainability Plan.
- Report the adequacy of HCHI's inspection and maintenance program and recommendation for improvements.

This report includes these deliverables. It is worth noting that for some of the assets categories only generic conclusions and recommendations based on the industry best practices could be made due to the lack of available data**.**

3 DEGRADATION MECHANISMS

This section contains descriptions of the degradation mechanisms for most of the asset categories within the scope of this project.

3.1 Distribution Station Transformers

The application of distribution station transformers generally involves the step down a higher to lower voltage. Substation transformers vary in capacity and ratings over a broad range. For Distribution stations, transformer ratings typically range from 5 MVA to 120 MVA.

Power transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary and secondary or tertiary windings
- Laminated iron core,
- Internal insulating mediums,
- Main tank,
- Bushings,
- Cooling system, including radiators, fans and pumps (Optional),
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

For a majority of transformers, End-of-Life (EOL) is expected to be caused by the failure of insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for substation transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks,

DC insulation resistance measurements and no load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonic and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for substation transformers usually include:

- Condition of the bushings,
- Condition of transformer tank,
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results and
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 40 to 50 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, EOL. There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Failure Mechanism of Power Transformers

1) ***Thermal Aging:*** Thermal aging involves the progress of chemical and physical changes because of chemical degradation reactions, polymerization, depolymerization, and diffusions.

2) ***Electrical Aging:*** Electrical aging, AC, impulse, or switching involves the effects of the following:

- partial discharges
- treeing
- electrolysis
- increased temperatures produced by high dielectric losses
- space charges

3) ***Mechanical Aging****:* Mechanical aging involves the following:

- fatigue failure of insulation components caused by a large number of low-level stress cycles
- thermo mechanical effects caused by thermal expansion and or contraction
- rupture of insulation by high levels of mechanical stress such as may be caused by external forces or operation condition of the equipment
- Insulation creep or flow under electrical, thermal, or mechanical stresses.

3.2 Distribution Station Circuit Breakers and Reclosers

The substation breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. Circuit breaker designs have evolved over the years and many different types are currently in use, such as oil circuit breakers, vacuum breakers, magnetic air circuit breakers and SF6 circuit breakers. HCHI uses Air Blast Circuit Breakers.

Air Blast Circuit Breakers (ABCB) use a blast valve to let an intense blast of high pressure air flow through a nozzle, along the arc drawn, between the fixed and moving contacts. The arc will be rapidly stabilized, cooled and interrupted by the cold air flowing along it. These breakers are supplied in a modular fashion so that each single phase of the three-phase breaker may consist of two or more columns supporting two or more interrupters, all connected in series to meet the specific system voltage requirements. The air blast breakers have high interrupting performance at the expense of increased complexity. Many HV air blast circuit breakers are fitted with opening and/or closing resistors and voltage grading capacitors across multi break designs. Maintainability and reliability issues become a concern.

Air blast breakers rely on a directly connected, external source, for supply of its interrupting medium. The primary interrupting medium is high-pressure compressed air that is fed from one or more central air compressor plants with suitably sized air storage facilities to accommodate all entire substation. Air blast breakers may also have a local high-pressure air receiver that has sufficient capacity to provide an Open-Close-Open operation without replenishment from the high-pressure central air system.

The air system used for air blast breakers must maintain the air dry. Consequently, air dryers on the central system and possibly locally are an integral part of the central air system and, therefore the breakers themselves. The air system needs to be considered as part of the overall breaker condition assessment

Substation breakers have many moving parts that are subject to wear and stress. They frequently “make” and “break” high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. In addition, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker’s specific duties. The International Council on Large Electric Systems’ (CIGRE) has identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete;
- Maintenance overhaul requirements; and
- Circuit breaker age.

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion;
- Effects of moisture;
- Bushing/insulator deterioration; and
- Mechanical;

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problem in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system and is a particular issue of concern in air blast breakers. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. In addition, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil and gas leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections;
- Oil contamination and/or leakage; and
- Deterioration of concrete foundation affecting stability of breakers.

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble (Power Factor) Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 25 to 80 years.

Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

3.3 Distribution Transformers

HCHI's population of distribution transformers consists primarily of pole mounted and pad mounted transformers with 3 vault room transformers. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid. All of these designs employ sealed tank construction.

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the health index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transfer operating age and winding temperature profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their distribution transformers for residential services to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as the reach near

the end of life (EOL), without actual failure. The average transformer life is expected to be approximately 40 years.

3.4 Poles

The support structures for overhead distribution circuits in HCHI are wood, concrete or steel poles. At locations with high mechanical loading, such as dead ends, angles and corners, the poles are typically supported by guy wires attached to anchors installed in the ground.

Wood poles are the most common form of support for overhead circuits. Wood species commonly used on distribution systems are predominately Red Pine, Jack Pine and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow and identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

Although wood pole condition assessment is driven by the condition of the wood pole itself, replacement of the ancillary components, of foundations, cross-arms, guys, anchors and insulators may also be required. The poles, foundations and cross-arms support the required insulation and phase conductors. The guys and anchors maintain the mechanical integrity of the structure and the insulators electrically insulate the conductor from ground potential.

The condition of the concrete poles is assessed by taking into consideration reduction in strength due to spalling or mechanical damage caused by vehicular collisions. Condition assessment of concrete poles can, similarly, be carried out through visual inspections and taking into account the extent of surface deterioration of the pole.

There are many factors considered by utilities when establishing condition of poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The life expectancy of wood poles or concrete poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

Steel pole designs always include a factor of safety much greater than one. Typically, steel pole foundations are cylindrical steel reinforced concrete structures with anchor bolts connecting the pole to its base although in some cases steel poles are direct buried. Common degradation processes include corrosion of foundation rebar, concrete spalling and storm damage. The strength of steel pole gradually decreases and structures reach end-of-life conditions when their actual strength falls below their design strength, or when the safety factor falls below one.

Corrosion of steel poles and hardware reduces their cross-sectional area causing a reduction in strength. Similarly, corrosion of tubular steel poles reduces the effectiveness of the tubular walls. Rates of corrosion may vary, depending upon environmental and climatic conditions (e.g., the presence of salt spray in coastal areas or heavy industrial pollution). Zinc galvanizing, protective paint coatings and a combination of galvanizing and painting help safeguard against excessive corrosion.

For galvanized structures, the degree of zinc coating loss (i.e., galvanization) provides a good indication of corrosion levels. Visual inspection can detect the degree of corrosion, the condition of protective coatings, and the extent of rust on steel members.

3.5 Switches

This asset group consists of distribution overhead line three-phase gang operated switches, manually operated as well as motor operated. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load

interruption, others are designed to operate under no load conditions, these switches operate only when the current through the switch is zero. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with switch handle locked in open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod,
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation,
- Loose connections
- Non functioning padlocks,
- Insulators damage,
- Missing ground connections,
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

The condition assessment of overhead switches involve visual inspections which would reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots.

The following parameters are considered in establishing the asset health:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks

- Condition of operating mechanism
- Operating age of disconnect switch

The average life expectancy of overhead switches is approximately 40 years. Consequences of overhead line switch failure may include customer interruption and health and safety consequences for operators.

3.6 Cross-Linked Polyethylene (XLPE) Underground Cables

Distribution system underground cables consist of underground cables, splices/joints, elbows, potheads and terminators at voltage levels 34 kV and below. It includes direct buried and installed-in-duct feeder cables, underground cable sections running from stations to overhead lines and from overhead lines to customer service connections and switches.

The use of insulated cables on distribution feeders has virtually become a standard in most North American jurisdictions for urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The initial capital cost of a distribution underground cable circuit is approximately three times the cost of an overhead line of equivalent capacity and voltage.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Underground cables are relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems unlike overhead lines, do not suffer from weather induced faults and have better reliability records.

Faults on underground cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable. Thus, the standard approach to cable system management has been based on reliability rather than the balance between and repair and replacement costs. As long as the reliability is within acceptable levels, it is virtually always cheaper to repair than replace cables.

Many utilities with high proportions of relatively old underground cables have concerns about reliability. Condition assessment programs enable utilities to prioritize the cable replacement programs based on available budgets.

Over the past 30 years XLPE insulated cables, due to their lower costs and easier splicing have all but replaced paper-insulated cables in new installations. The existing population of XLPE cables is still relatively young in terms of normal cable lifetimes. Therefore, failures that have occurred can be classified as early life failures. In the early days of polymeric insulated cables, their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced during manufacturing. Over the past 30 years many of these problems have been addressed, and modern XLPE cables and accessories are generally considered very reliable if manufactured and installed through competent workmanship.

Polymeric insulation is very sensitive to discharge activity. Thus, cable, joints and accessories must be discharge free when installed. Water penetration into the insulation/conductor barrier, existence of impurities within the semicon layer and presence of high dielectric stress are the principal causes of insulation treeing and the most significant degradation processes for earlier generation of polymeric cables. The rate of water tree growth depends on the quality of the polymeric insulation and the manufacturing process. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs with metal foil barriers and water migration controls have further reduced the rate of deterioration from treeing.

Examining recovered failed cable samples to detect and quantify treeing serves as an effective means to assess the general condition and estimate the future life of XLPE cables. Alternatively, accelerated electrical testing of recovered cables can also be used to determine condition.

Most utilities are beginning to determine the condition of their cables through lab testing and in-situ testing. In the absence of testing, the only other indicators of cable heath are:

- Number of failures per unit length of installation
- Age of Cables.

At this time, the realistic life expectancy of XLPE cables is difficult to ascertain. There is concern that these cables will have a shorter lifetime than the earlier paper insulated cables, but experience is still limited. The life expectancy of TRXLPE cables is considered in excess of 40 years.

The major consequences of cable failure are adverse impacts on reliability. Fundamentally, end of life cannot be predicted since most insulation system failures are related to the occurrence of a transient event such as an overvoltage caused by breaker operations, lightning strikes or flashovers, etc and the occurrence of a transient event. However, via diagnostic testing, the condition of the insulation can be assessed to the point where the occurrences of a transient event will likely result in a failure.

4 ASSET CONDITION ASSESSMENT (ACA) METHODOLOGY

4.1 Determining Health Index (HI)

Health Indexing quantifies equipment condition based on numerous condition criteria related to the long-term degradation factors that cumulatively lead to an asset's end-of-life. Health Indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating for some time prior to reaching its end of life.

When using the Health Indexing method it is important to understand the differences between defect management and the resultant reactive maintenance versus long-term asset degradation and asset condition assessment. Defects are usually well defined and are due to failed or defective components in the ancillary systems that affect operation and reliability of the asset well before it reaches end of life. These defects do not normally affect the life of the asset itself, if detected early and corrected. Defects are routinely identified during inspection and dealt with by corrective maintenance activities to ensure continued operation of the asset.

Long-term degradation is generally less well defined and is not easily determined by routine inspections. The purpose of asset condition assessment is to detect and quantify long-term degradation and to provide a means of quantifying remaining asset life. This includes identifying assets that are either at or near their end-of-life or are at high risk of generalized failure that will require major capital expenditures to either refurbish or replace them.

A good understanding of the asset degradation and failure processes is vital if condition assessment procedures are to be effectively applied. It is important to identify the critical modes of degradation, the nature and consequences of asset failure, and, if possible, the time remaining until the asset is degraded to the point of failure. In order to establish proper assessment criteria and to define appropriate end of life criteria it is essential to have a good understanding of the degradation and failure processes.

A composite Health Index is a very useful tool for assessing the overall health of a complex asset. Transmission and distribution assets are typically comprised of multiple subsystems, each with its own modes of degradation and failure. Depending on the nature of the asset, there may be one dominant mode of failure, or there may be several independent failure modes. In some cases, an asset may be considered to have reached its end of life only when several subsystems have reached a state of deterioration that precludes continued service. The composite Health Index combines all of these condition factors using a multi-criteria assessment approach into a single indicator of the health of the asset.

For a typical asset class, a wide range of diagnostic tests and visual inspections may be undertaken, either as part of the ongoing maintenance program or as special-purpose Asset Condition Assessment (ACA) surveys. In some cases, a poor condition rating value will represent a failure of a single subsystem which can be addressed through replacement of that subsystem, without the need to replace the overall asset. However, it should be recognized that generalized deterioration of many or all of the subsystems that make up an asset could also be a valid indication of the overall health of the asset.

A composite Health Index captures generalized deterioration of asset subsystems, as well as “fatal” deterioration of a dominant subsystem.

In developing a composite Health Index for an asset, it is very important to understand the functionality of the asset, and the manner in which the various subsystems work together to perform the key asset functions. With a clear understanding of asset functionality, condition ratings of different asset components and subsystems can be combined to create a composite “score” or Health Index for the asset, and the continuum of asset scores can be subdivided into ranges of scores that represent varying degrees of asset health.

The critical objectives in the formulation of a composite Health Index are:

- The index should be indicative of the suitability of the asset for continued service and representative of the overall asset health
- The index should contain objective and verifiable measures of asset condition, as opposed to subjective observations
- The index should be understandable and readily interpreted

Development of a condition-based Health Index requires an assessment of the relative degree of importance of the different condition criteria in determining the overall health of the asset. Each condition criteria must be assessed as falling into one of the four categories shown in Table 4-1 below.

Table 4-1 Relative Degree of Importance of Condition Criteria

No Impact Criteria	**Indicator reflects defects or deterioration measures that have no impact on overall asset health e.g. Silica gel in Transformers**
Contributing Criteria	**Indicator reflects defects or deterioration measures that range from low to high in importance, but typically in combination with other measures as part of a formulation of generalized deterioration, e.g. Contacts in Circuit Breakers.**
Combinatorial Criteria	**Indicator reflects a measure which does not represent asset condition in isolation, but is a critical component in a complex logical and/or mathematical formulation of asset health, e.g. Oil Quality Test in Transformers.**
Dominant Criteria	**Indicator reflects the health of dominant subsystem that makes up the asset, and end-of-life based on this single factor can represent end-of-life for the entire asset, e.g. DGA Test in Transformers or remaining strength in Wood poles.**

By using a multi-criteria analysis approach, the various factors can be combined into an idealized condition-based Health Index. This involves grouping together the various factors, creating the mathematical and/or logical formulations, and establishing the importance weightings of all the factors in order to combine them into a single, overall Health Index for the asset.

A quantified scoring system can be developed to appropriately represent the asset health consistent with this methodology. This involves the following steps:

1. "Deterioration" assessments or scores are converted to health scores in a defined range from "perfect health" to "end-of-life".

2. Importance weighting is assigned to each factor in a range from "modest importance" to "very high importance" based on the definitions in the Table 4-1 above.

3. General deterioration index is formulated by calculating the maximum possible score by summing the multiples of steps 1 and 2 for each factor.

4. The general deterioration index is normalized to a maximum score of 100 based on having a defined acceptable/minimum number of condition criteria available.

5. The dominant Criteria are normalized to a maximum score of 100.

6. The overall Health Index is calculated where 1 or 100% represents excellent health and 0 or 0% is "poor" or end of life health.

7. The continuum of asset health scores is correlated into typically five categories of asset health from "Very Poor" to "Very Good". This conversion into discrete categories for a condition index requires fine-tuning of the health scoring system to ensure that the relative degree of severity of the scores due to "dominant" criteria and those due to generalized degradation match up at the boundaries between each category. This may require iteration of the individual steps to ensure that the resulting index is rational and coherent, and reasonably reflects field condition.

Normally, with many condition factors, the Health Index is seldom less than 0.25, because some of the factors will indicate good condition. The interpretation of the Health Index to obtain effective age and probability of failure must therefore be based on the premise that a Health Index of 0.25 indicates that the asset is at its end of life.

Because a given asset may not have data for all possible condition criteria, an additional factor called the data availability indicator or DAI is calculated. The DAI is determined by the ratio of the "best" weighted condition score for the subset of condition criteria data available for this asset over the "best" overall weighted, total condition score. An asset with all condition criteria data represented will, by definition, have a DAI value of 1 or 100%. In this case an asset will have a DAI of 100% even if the Health Index score is low. If an asset has a low value of DAI (less than 50% for example) then the Health Index score will probably not be based on enough information to include this asset in any subsequent capital plans for refurbishment or replacement until more condition criteria data are found.

4.2 Simple Relation of Health Index to Probability of Failure

The ideal relationship would be to have "Condition" (quantified by the Health Index) be directly related to failure probability based on experience. For wood poles, for instance,

one could say that the Condition or strength at the present time and the rate of loss of strength could be directly related to the end of life of the pole. Unfortunately, there is little empirical evidence for most classes of assets of a direct relation between condition, as indicated by Health Index, and probability of failure and remaining life.

In a simplified manner one could map the Very Good, Good, Fair, etc categories to probability of failure as illustrated below. The Health Index categories (Very Good, Good, etc) could also be mapped directly to replacement timing as indicated in the Figure 4-2 and Table 4-2 below.

Figure 4-2 Simplified Estimating of Probability of Failure from the Health Index

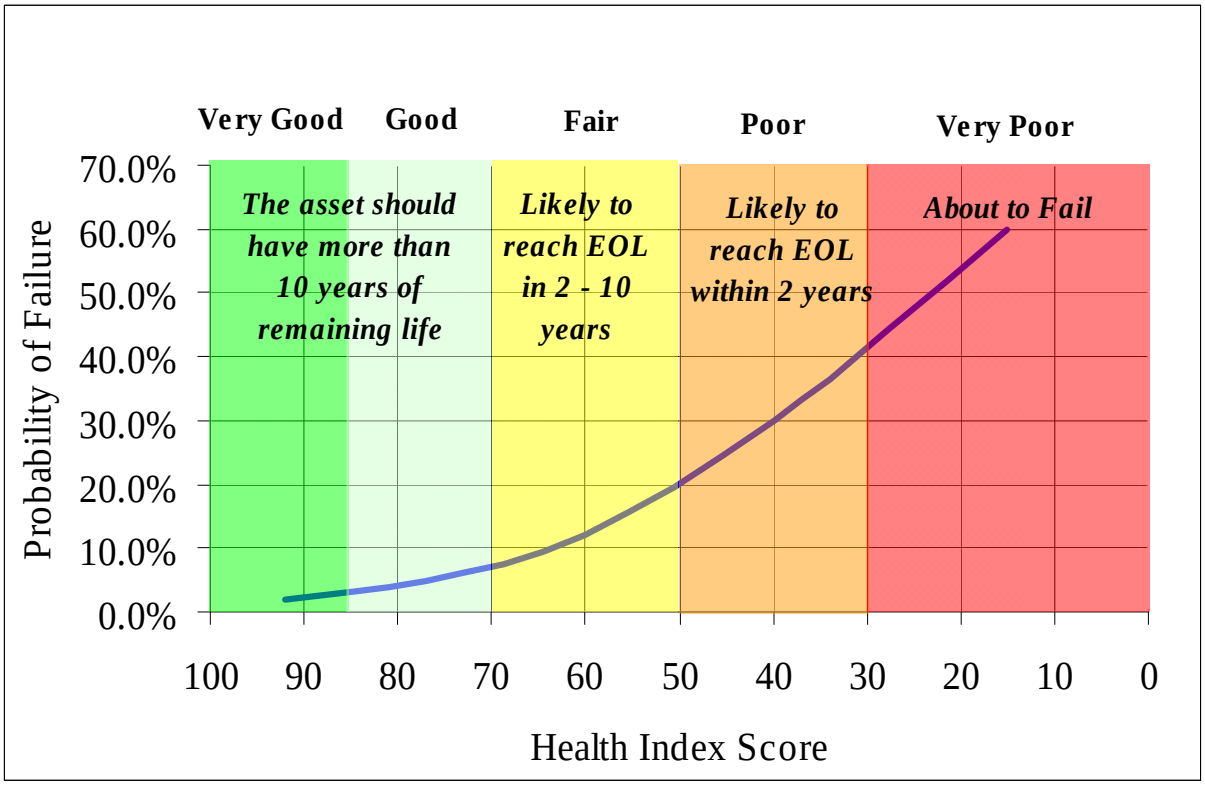


Table 4-2 Health Index Scale

Health Index	Condition	Description	Expected Lifetime	Requirements
85 – 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 15 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	More than 10 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 3 – 10 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 3 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

4.3 Determination of Failure Rates

The failure rate curve for a component is obtained by adapting a standard textbook "bathtub" curve (which is an exponentially increasing failure rate) so that it matches the median life and maximum life that has been observed to typically occur in the industry or at a specific utility. The form of the failure rate vs. age equation is $P_F = e^{B(x-A)}$, where A and B are constant parameters that control the location and steepness of the exponential rise (*x* is the variable representing age in years). Other failure rate curves are sometimes used. A common practice is to add a constant term to capture the low failure rate of new equipment, so that the curve does not go to zero failures at zero years. This constant is typically about 0.005. It is omitted in this formulation because it would have an insignificant effect on the resulting replacement decisions near end of life. If the actual failure rate data is available it may be necessary to use a more complicated exponential function; however, in this case, a better practice is to fit the data with a Weibul distribution which can be used to model an exponential probability function and can also be adjusted to more accurately fit the data if the function is not quite an exponential form. The simple exponential is as accurate as it is possible to be when data does not exist. When a Weibul statistic is used the failure rate curve is the probability density function divided by one minus the cumulative probability.

If no data for failure rate vs. age is available then the A and B parameters of the failure rate equation can be determined from estimates of the median age of failure and the maximum age based on the utility experience. It is important to use the experience of a specific utility when it is available since operating conditions, environmental factors, and

maintenance practices affect equipment failure rates. Figure 4-3.1 shows a cumulative failure vs age curve fitted to a median age at failure of 53 years and a maximum age (defined as 99% of all units failed) of 75 years.

Figure 4-3.1 Cumulative Failure Probability

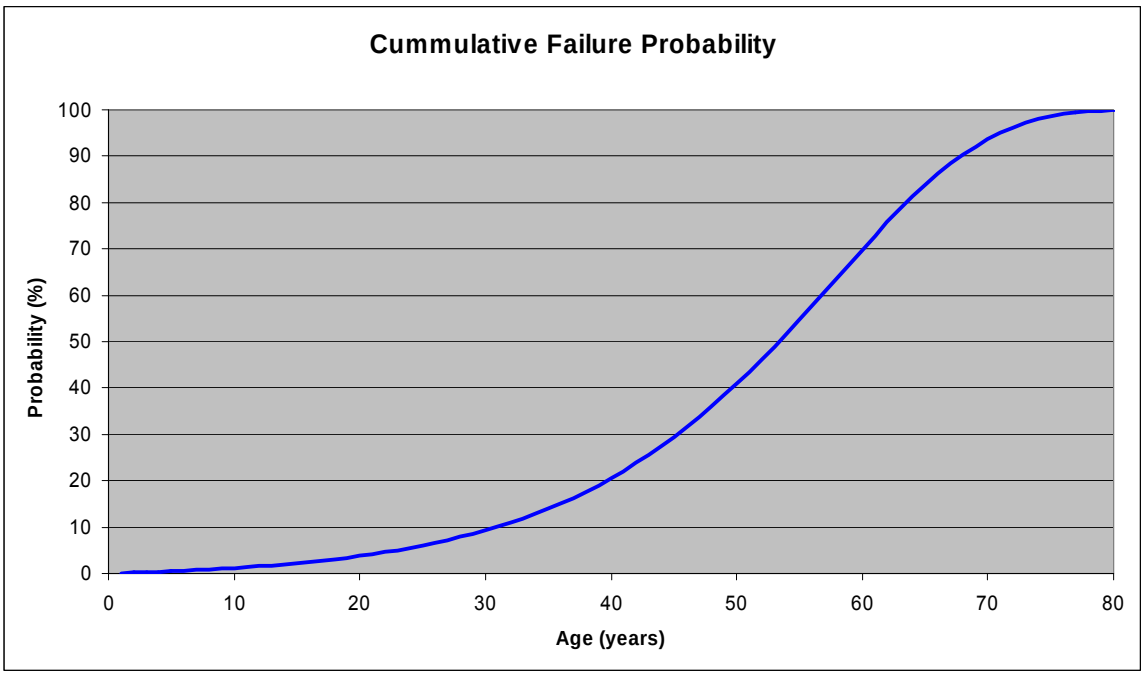
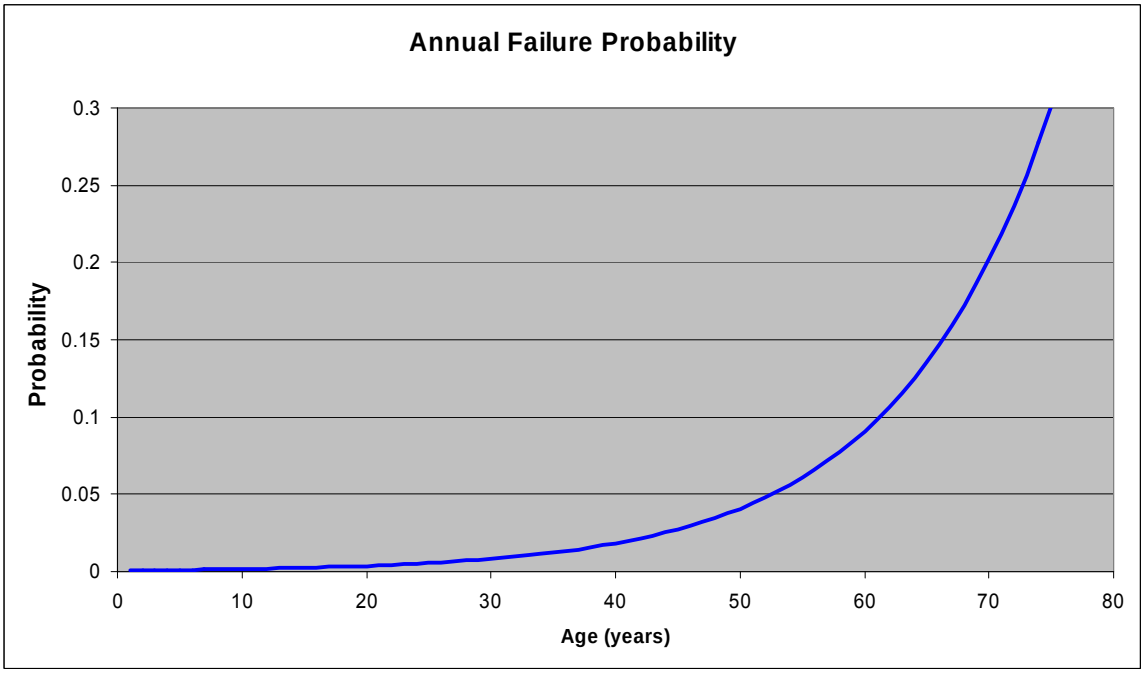


Figure 4-3.2 shows the same failure data as annual failure probability.

Figure 4-3.2 Annual Failure Probability



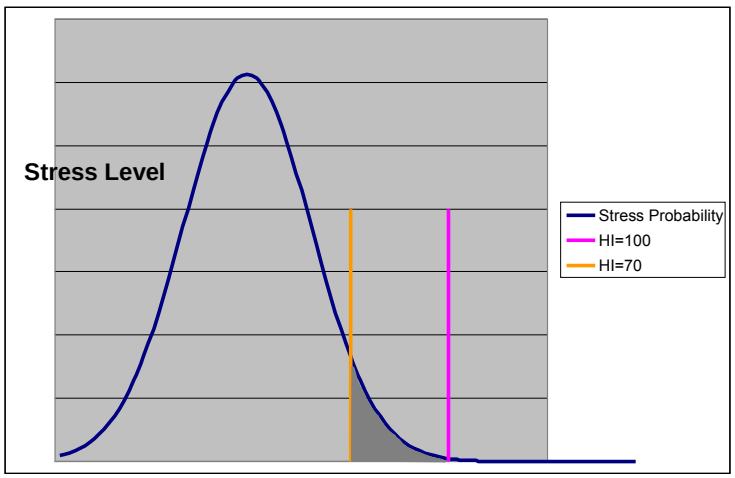
4.4 Quantitative Relation of Health Index to Probability of Failure

Once the equation of the failure rate curve is known ($P_F = e^{B(x-A)}$) then it can be used to determine the probability of failure when the health index is 1, by setting x=0. Another point can be determined by calculating the cumulative probability and defining a maximum life when the cumulative probability of failure is equal to 99%. The age at which this occurs can be used in the formula to calculate the annual probability of failure at a Health Index of 0.25 (as described earlier, the Health Index value of 0.25 is interpreted as the end of life). This determines two points on the curve of health index vs probability of failure.

In developing the full relationship between Health Index and probability of failure it is useful to consider how condition and probability of failure are related. Each asset could be considered to have a certain condition or strength. Whether it fails or not depends on whether the stresses in the field exceed this strength. The stress, that each component experiences, varies around a mean value with a somewhat “normal” frequency distribution. The probability of the stress exceeding the strength leads to the probability of failure. Figure 4-4 shows the probability density function of stress that a component experiences in service. The probability of failure is proportional to the area under the stress probability curve to the right of the line representing asset strength (the dark shaded area), i.e. the area where the stress is larger than the strength.

The normally distributed stress curve leads to a relationship between condition and probability of failure that is not linear i.e. as strength decreases (vertical line moves to the left) the probability of failure increases at a greater rate. Other stress probability distributions can be used if data exists to indicate that a normal distribution is not appropriate, but sensitivity studies have shown that, once the two points are defined, the exact form of the distribution is not a sensitive parameter in the overall risk of failure analysis.

Figure 4-4 Failure Probability Related to Health Index



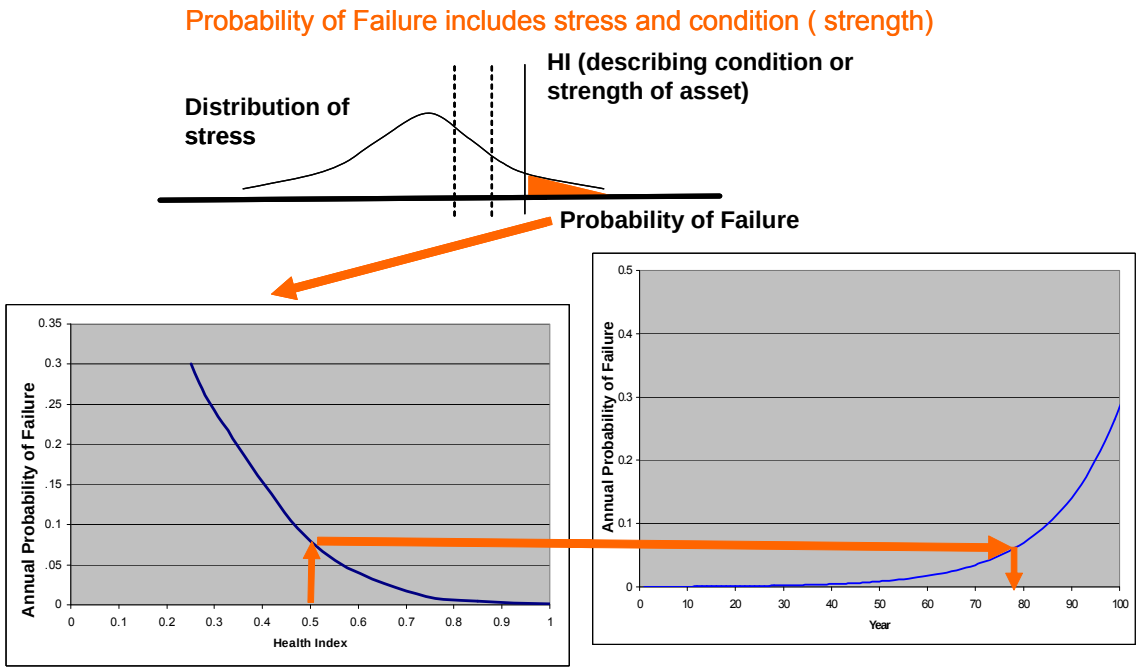
The two points of Health Index and probability of failure (at new, Health Index=1 (100%) and end of life, Health Index=0.25 (25%)) can be used to generate the probability of failure at other Health Index values. Consider the health index to represent the "strength" of a component. As the health index moves linearly from 1 to 0.25 the vertical line in Figure 4-4 moves linearly to the left. As it moves the probability of failure at each health index is proportional to the area it has passed under the normal curve. This establishes the relationship between Health Index and probability of failure.

4.5 Relating Health Index to Effective Age

The relationship between Health Index and the probability of failure can then be used to relate Health Index to "effective" age. The probability of failure associated with a specific Health Index value is determined from the left hand graph of Figure 4-5. The associated probability of failure is then found on the right graph (the failure rate vs age graph determined previously) and the "effective age" is read off the horizontal axis of the right hand graph.

The Condition derived from the Condition Parameters, when mapped to Probability of Failure, will provide an Effective Age of the Asset.

Figure 4-5 Relation of Asset Condition and Effective Age



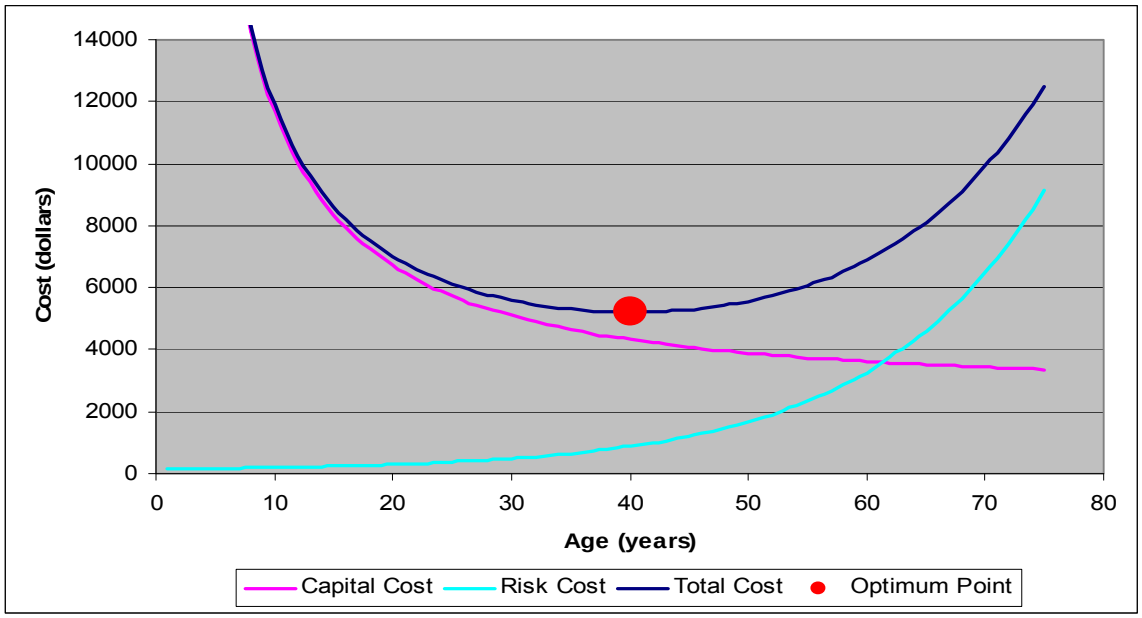
4.6 Repair vs Replace Decision Risk Analysis

Once the Health Index has been determined for an asset, and the "effective age" has been calculated from it, then the next step is to assess the risks and determine the optimal time for intervention to reduce the risk if action is required. The intervention can be in the form of replacement, refurbishment or increased monitoring.

The risk is assessed by assigning a dollar value to the positive and negative aspects of each alternative date for intervention. The positive effect of delaying intervention is to reduce the annual capital cost. If an asset worth $10,000 is replaced in 10 years its effective annual capital cost, to pay for the asset and the cost of using the capital (assumed to be 6% per year), would be $1360 per year. If the same asset is replaced after 20 years the annualized cost is $870 per year. The negative effect of delaying intervention is an increasing maintenance cost, and an increasing probability that the costs associated with equipment failure will be incurred. The utility costs associated with failure include the replacement cost of the asset, any collateral damage to adjacent equipment, environmental clean up costs, overtime labor premiums, and the lost revenue from unsold energy. Some utilities also include the cost of interruptions to customers. The expected value of the negative effects of delaying intervention is estimated by multiplying the probability of failure by the costs associated with failure. This number is often referred to as the "risk cost" or "consequence cost". As the intervention is delayed more years the probability of failure increases and this increases the risk cost.

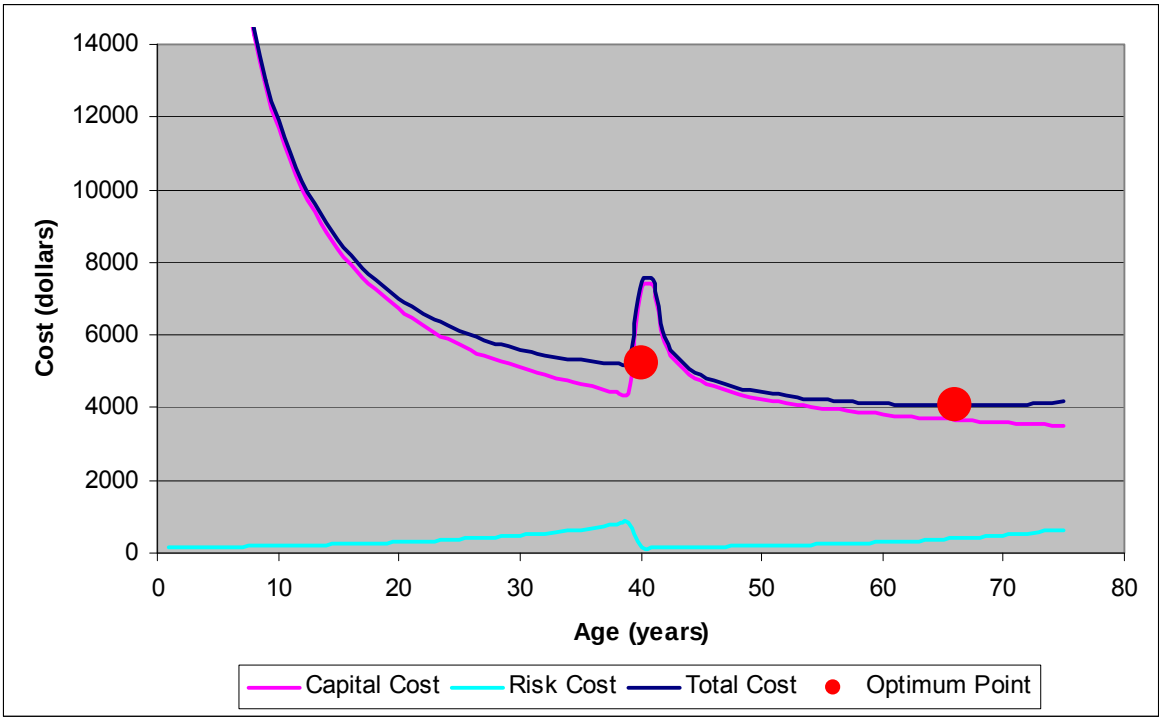
The method is illustrated in the Figure 4-6.1. While the annualized capital costs are decreasing with time, the risk cost is increasing. The total cost can be seen to have a minimum point. This is the optimal time to intervene to reduce the risk costs. If the asset is replaced at year 40 the annualized capital cost is $5,200. If the intervention is replacement, then Figure 4-6.1 shows all of the necessary information.

Figure 4-6.1 Example Risk Optimization with Simple Replacement



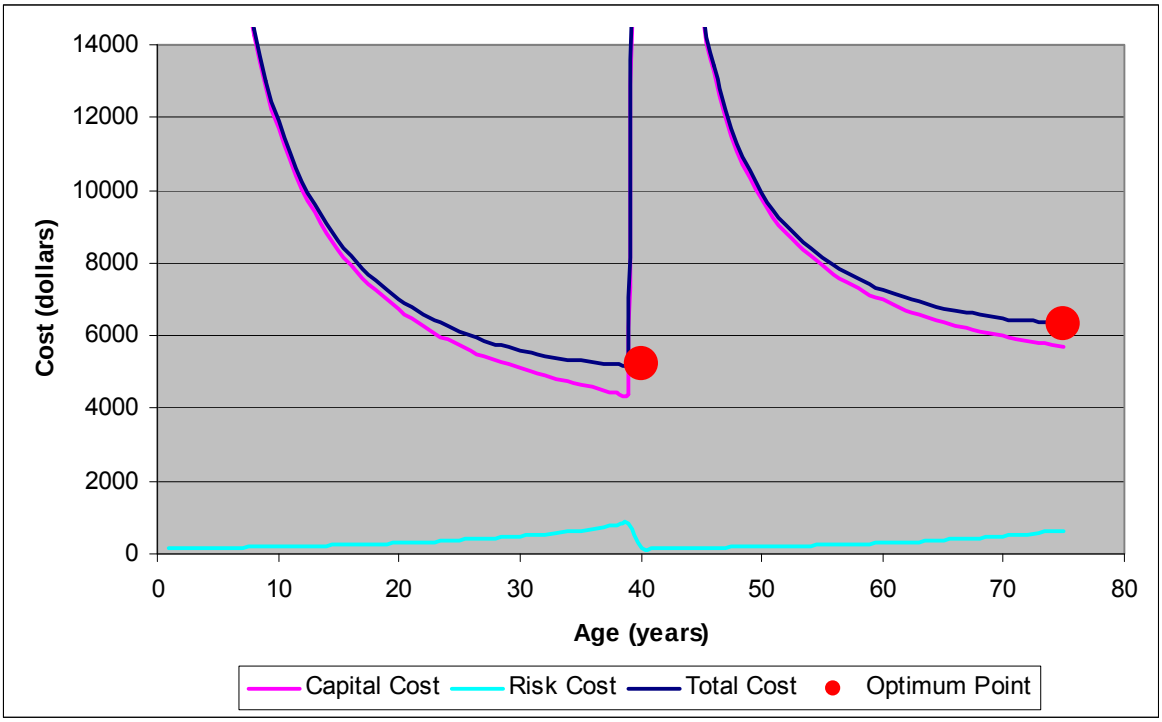
However, if the intervention is refurbishment then the analysis must be extended to include the ultimate optimal replacement. In the case of refurbishment, in the optimal year for intervention, the capital cost is increased by the cost of the intervention (this assumes the refurbishment cost is large enough to be capitalized) and the risk costs are decreased in future years by a factor that reflects the effectiveness of the intervention. For example, a given refurbishment may decrease the probability of failure by 90%, but not return the unit to new condition. The results are illustrated in Figure 4-6.2. A twenty year old asset with a capital cost of $100,000 was assessed to have a health index of 0.9, giving it an effective age of 19 years. The average end of life for that type of assets was 75 years with a maximum of 100 years. The optimal year for the first intervention to reduce risk was year 40. In this hypothetical example this is quite early in the asset's life, because the capital costs are dropping slowly with each passing year and the maintenance and risks costs only have to increase a small amount to justify a need for refurbishment. Figure 4-6.2 shows $3,000 was spent to refurbish the asset in year 40, returning its health index to 1. At year 66 the increasing risk cost has made a further intervention optimal. The overall annualized cost for the asset over its life is $4,050. Since this is lower than the $5,200 resulting from replacement at 40 years, the refurbishment would be the preferred alternative in this case.

Figure 4-6.2 Example Risk Optimization with Refurbishment Cost Effective



However, if the refurbishment cost had been higher, say $50,000, and then the optimal final replacement would have occurred at a higher total annualized cost, indicating that the refurbishment was the more costly option. This situation is shown in Figure 4-6.3. The overall annualized capital cost with refurbishment is $6,300. Since this is higher than the replacement option ($5,200), the replacement at the first optimal year of intervention would be the preferred alternative in this case.

Figure 4-6.3 Example Risk Optimization with Refurbishment Not Cost Effective



5 HEALTH INDEX FORMULATION

5.1 Generic Formulas

For HCHI, generic Health Index formulas were used for Distribution Station Transformers (Group A) and Poles (Group F) to calculate Health Index from the Condition Parameters and, for more complex Condition Parameters, from Condition Parameter Factors:

$$HI = \frac{\sum_{m=1}^{5} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{5} \alpha_m (CPS_{m.max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{n=1} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1} \beta_n (CPF_{n.max} \times WCPF_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter

CPF --- Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable).

For the rest of the asset categories sufficient information for using similar specific formulas was not available. Instead, the assets age distribution provided by HCHI was used in conjunction with the typical industry-established age-based failure curves to estimate HI distribution.

In addition, some of the calculated and estimated Health Indices were modified based on the expert opinion obtained from the interviews with the HCHI staff to reflect local knowledge and experience regarding the assets condition, and a one-day field observations conducted jointly by Kinectrics and HCHI staff. Both HCHI's expert opinion and results from the field observations are summarized in Sections 5.3 and 5.4, respectively, of this report.

5.2 Data Availability

HCHI had sufficient data available for most of the distribution station transformers (Group A) and some of the poles (Group F). The Data Availability Indicator (DAI) and prioritized data requirements for these Asset Groups are shown in Appendix III.

There was no information other than age for the rest of the Asset Groups (with the exception of some IR results for the Gang operated Overhead Switches. For these Asset

Groups rather than DAI a percentage of units with the known age along with the prioritized data requirements are also shown in the Appendix III.

It is worth noting that even though only age information was available for the Circuit Breakers, this presented no problem at this time because these breakers are fairly new. However, going forward it is essential to start collecting the required condition information as breakers are major assets whose condition needs to be monitored based on the results of the periodic testing.

5.3 Expert Opinion

In constructing HI methodology for HCHI asset groups, expert inputs from HCHI are embedded.

As per Kinectrics' interview with HCHI on-site staff, the following issues were taken into account in deriving HI:

Asset Group C, Pole Mounted Transformers

According to HCHI, CES transformers seem to be failing more than other makes. To reflect such information, an extra asset condition is introduced as a multiplier factor for the overall HI, so that in the case of CES transformers the total HI score is discounted.

Asset Group F, Poles

HCHI's field staff indicated that poles of Southern yellow pine type are typically in a worse shape as compared to others. In Kinectrics HI calculation an extra asset condition is introduced as a multiplier factor for the overall HI, so that in the cases of Southern yellow pine poles, the total HI score is discounted.

HCHI staff also mentioned that poles that are 20 years or older in Dunnville area have a bad record in terms of performance. In Kinectrics HI calculation an extra asset condition is introduced as a multiplier factor for the overall HI, so that in the cases of the Dunnville area 20 year or older poles, the total HI score is discounted.

Asset Group G, Gang Operated Overhead Switches

The newer ones are in the good condition but the older ones seem to be in the need of replacement. In identifying assets for replacement, it was assumed that switches that are 30 years old or more need to be replaced.

Asset Group J, Three Phase Reclosers

HCHI experienced a number of problems operating Joselyn reclosers. The remaining 3 Joselyn reclosers are expected to be replaced over the next couple of years.

5.4 Field Observations

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets.

The objectives of the inspection was to confirm the accuracy of the asset lists and condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available.

Visual inspection was conducted for all substations owned and operated by HCHI, and for a selected sample of the distribution lines, pad mounted switchgear and transformers on the underground system. All of the facilities were inspected directly by staff that traveled to the sites accompanied by HCHI employees. The overhead system was inspected at a sample of 14 locations including 5 load break switches, 13 wood poles and 11 pole mounted transformers. The sample locations covered every distribution voltage level and age of line. On the underground system, 12 locations were inspected including 6 pad mounted switches and 7 pad mounted transformers.

Each piece of equipment and their components were given a rating of A, B, C, or D. The ratings can be classified generally as:

- A: New condition. No signs of wear or age.
- B: Some minor signs of wear or age. No maintenance required.
- C: Definite signs of wear or age. Some minor maintenance may be required, such as painting.
- D: At end of life or major maintenance required.

In general, the documentation available provided a reasonable description of the facilities observed in the field visits. Not all identified problems had been repaired, which is one indicator that the system is not over-maintained. The transformer stations, overhead lines, and underground systems generally appear adequately maintained.

Some of the notable observations from the field inspections are provided below.

Substations

The substations are generally in good condition for their age, although their average age at 48 years is older than the average age for most utilities. There were many indications of recent maintenance, including cleaned and replaced bus support insulators and bushings, fresh gravel, and rewound transformers. Fences were all complete; gates locked and ground wires intact.

Although there was some evidence noted of previous oil leaks at several stations, only one active leak was found at an elbow joint in a line from a conservator tank to the main tank at Decewsville Regulating Station.

Metal tanks, oil coolers and bus supports showed signs of surface rust and some peeling paint, but no structural problems were noted.

Concrete foundations are generally in very good condition. The one exception was at Nanticoke DS where a bus support foundation was seriously crumbling. Several other bus support foundations at this station had been rebuilt already.

General results of the items inspected were: 21% category A, 47% category B, 30% category C and 6% category D.

Overhead System

Sites for overhead system inspection were selected to offer a variety of voltage classes, urban\rural mix, and representative ages.

There were no observations of oil leaks or severe corrosion or rot. All of the assets appeared to be in good condition for their age. There were no signs of overloading or lack of maintenance. There were no observations of trees limbs encroaching on conductors.

The results of recent pole inspections were evident with the worst looking poles marked for replacement.

The only observation of immediate maintenance required was a broken arrester that had a lead hanging down and possibly paralleling the fuse.

On one section of overhead line south of Caledonia (pole 018461 and adjacent poles) the polymer insulators were apparently dirty and the surfaces starting to deteriorate. Several other line sections were observed to have been recently rebuilt with new poles and hardware and sometimes new conductors.

This mix of conditions is considered typical of well maintained lines.

The condition of many transformer bushings could not be assessed because animal guards covered them.

A summary of results is shown in the Table 5-4.1 below.

Table 5-4.1 Summary of Field Observations for the Overhead System

	Condition A	Condition B	Condition C	Condition D
Load Break Switches	41%	55%	4%	0%
Poles	9%	61%	30%	0%
Pole mounted Transformers	4%	80%	16%	0%
Total Overhead	12%	69%	18%	1%

Underground System

Visual inspections of pad mounted transformers and switchgear were made as well as reviewing pictures of subsurface equipment (one vault).

The underground system equipment was found to be in good condition. The only defect conditions observed were a cracked fiberglass base on a pad mount transformer, some oil seepage at a corroded seam on another, a missing drain wire on a high voltage elbow connector and excessive moisture in three pad mounted switch enclosures. The excessive moisture is not a condition parameter directly, but it can lead to premature failure due to insulator contamination or tracking on barrier boards.

The equipment in the one vault was all in good condition, based on the pictures supplied.

A summary of results is shown in Table 5-4.2.

Table 5-4.2 of Field Observations for the Underground System

	Condition A	Condition B	Condition C	Condition D
Pad Mounted Switchgear	45%	53%	2%	0%
Pad Mounted Transformers	36%	42%	19%	3%
Cables and Terminations	14%	77%	7%	2%
Total Underground	29%	59%	10%	2%

6 RESULTS

6.1 Results Provided for each Asset Group

The detail results for each of the Asset Groups are shown in Appendix III and include the following information:

1. HI distribution
2. Age distribution
3. DAI for Asset Groups A and F and percent of the assets with known age for the remaining Asset Groups
4. Number of units that is recommended to be replaced annually.
5. Replacement cost over the next 20 years

As stated earlier in this report, Health Index methodology was used as described in Appendix I for Distribution Station Transformers (Group A) and in Appendix II for Poles (Group F). For the remaining Asset Groups age information in conjunction with the typical age-based industry failure curves was used in estimating HI distribution.

The results also include Expert Opinion and Field Observations described in Sections 5.3 and 5.4 of this report.

Since information both for using HI methodology and age estimation was only available for some of the assets within each group, HI and age distribution for the whole population was extrapolated from the known data assuming that they provide a good representation for the whole population.

6.2 Data Requirements

DAI for Asset Groups A and F and percentage of the assets with known age data for the remaining Asset Groups could be used as a measure of HI credibility, i.e. the higher the DAI or the percentage of available age data, the more confidence one has in the HI and associated results.

Appendix IV shows the strategy for prioritized closing of the data gaps. The required data are divided into three categories depending on their impact in determining HI with P1 being the highest and P3 being the lowest level of importance.

When the information was available only for some of the assets within an Asset Group, an assumption was made that this information will continue to be collected until eventually it becomes available for all the assets and, thus, no special provision is required to start collecting it.

6.3 Projection of Capital Replacements

Capital Replacements Plan (CRP) includes projections of the number of units to be replaced for each Asset Group and replacement cost over the next 20 years assuming a 2% annual discount rate and HCHI and Kinectrics provided replacement values shown in the Table 1-4.

In estimating a number of units to be replaced two distinct approaches were used as follows:

Proactive Approach

This approach was used for Asset Groups A, F, G and J and it involves replacing assets before they failed. For the Asset Groups A and F this was based on the HI methodology described in Appendix I and Appendix II and associated effective age and risk assessment techniques. For the Asset Groups G and J the replacements were based on the expert opinion recommendations.

In the future, it is imperative to also get enough information for the Asset Groups B and I to ensure that the station breakers and underground feeders are replaced or refurbished before they fail as associated risk of failure costs are typically high.

Reactive Approach

This approach was used for the remaining Asset Groups (including I due to the lack of non-age information for this Asset Group) and it involves merely estimating number of assets in each group that are expected to fail each year based on their age distribution and typical industry failure rate curves. For these assets risk of failure (except for the underground cables) is not significant and they are typically run to failure with no or little condition data available.

Overall Capital Replacement Plan (CRP)

Overall CRP is merely a total of the replacement projections for all the assets and it is shown in Figure 6.3-1. Since replacement costs for the assets replaced *reactively* are linked to the probability of failure, the only opportunity to levelize CRP envelop is by deferring some of the *proactive* replacements. Figure 6.3-2 shows Levelized overall CRP with Distribution Station Transformers, Poles and Underground Cable replacement “smoothed out” so as not to increase the risk of failure.

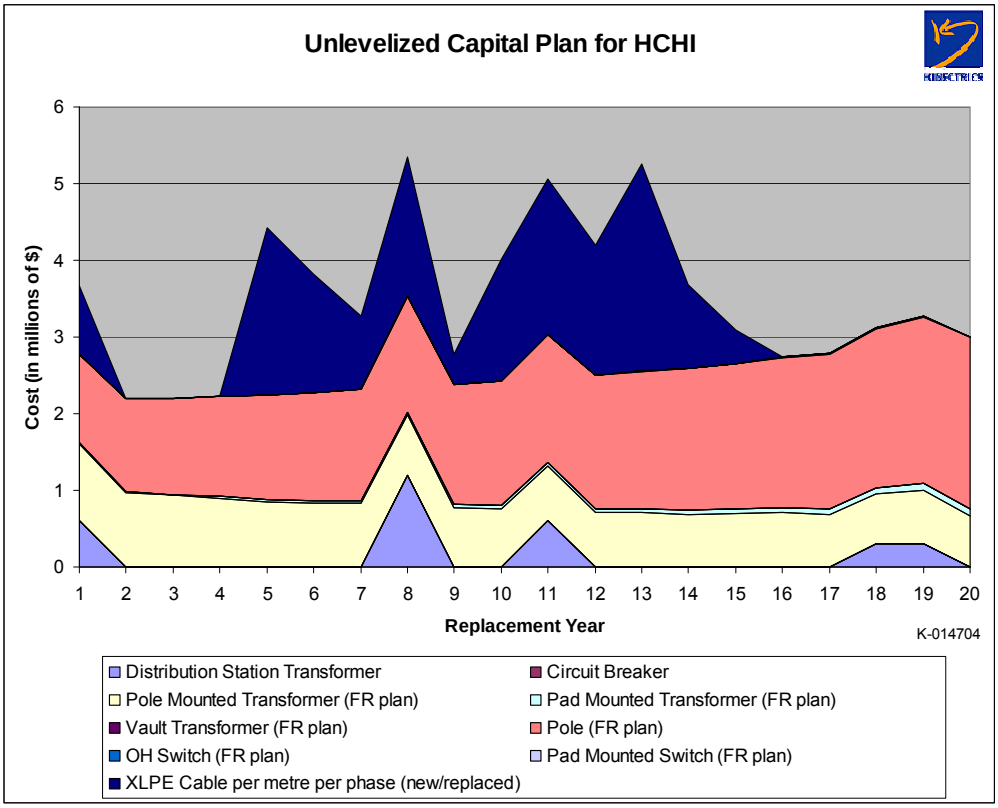


Figure 6.3-1 Unlevelized Capital Plan

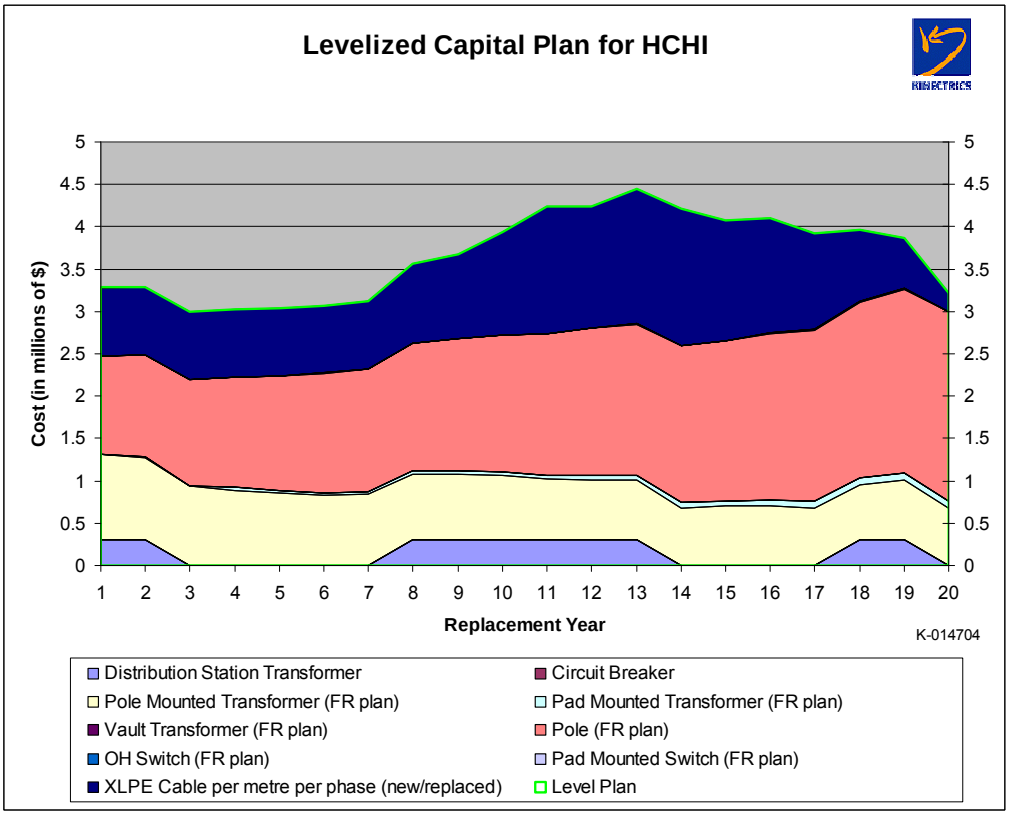


Figure 6.3-2 Levelized Capital Plan

6.4 Evaluation of Maintenance Practices

The Distribution System Code's guidance on recommended maintenance practices for LDCs is intended to help maintain system reliability & safety. Good utility practices, inspections cycles, qualification of persons, defect repair, customer notification are addressed.

Haldimand County Hydro Inc's Distribution System Maintenance and Inspection Procedure is divided into the following components:

1. Line Clearing and Tree Trimming Maintenance Program
2. Substation Maintenance Program
3. Distribution Plant Inspections
4. Off Road High Voltage Line Inspections
5. Thermography Inspection Program
6. Switch Maintenance Program
7. Hydraulic Reclosers Maintenance Program
8. Electronic Reclosers Maintenance Program
9. Voltage Regulator Maintenance Program

HCHI's maintenance program is well structured. Important areas are addressed, such as:

1. Identification of persons responsible for remedial actions.
2. Maintenance practices based on accepted & peer reviewed industry standards.
3. Clearly articulated inspection protocols, along with website links for further information.
4. Cycling of inspection & maintenance activities that are in accordance with budgetary & system degradation parameters.
5. Well defined job numbers for financial reporting requirements.
6. Deferral of certain inspections. These asset classes have been prioritized for startup of inspection & maintenance activities at a later date.
7. Refurbishment (as in the case of reclosers) by outside companies where HCHI does not have the capability in-house.
8. Pole numbering & GPS location recording.
9. Data recording in MS Access.

HCHI's inspection and maintenance practice is clearly defined, prioritized, has clear reporting & remediation responsibility structures, based on accepted industry standards, and is technically and financially sound.

7 CONCLUSIONS AND RECOMMENDATIONS

1. Based on the data and Expert Opinion provided by HCHI and joint Field Observations, HCHI's assets are generally in a "good" condition with the Asset Groups overall Health Index ranging from 67% for Overhead Reclosers and 100% for the Circuit Breakers.

2. The data collection by HCHI is compatible with that of other utilities of comparable size. Nevertheless, there are data gaps that need to be closed to increase confidence in the Asset Condition Assessment Results, specifically:

   - Continue with the pole testing program and collect age information for all the poles (Asset Group F)
   - Put in place a periodic testing program and start collecting condition information for Station Circuit Breakers (Asset Group B)
   - Continue with collecting existing condition information for Distribution Station Transformers (Asset Group A) and start collecting more data as per Appendix IV
   - Put in place a periodic testing program and start collecting condition information for underground cables (Asset Group I) as per Appendix IV
   - For the remaining Asset Group collect age information for all the units

3. A concentrated effort to replace assets in the following Asset Groups is required:

   - Based on the pole testing program results, about 300 poles/year should be replaced over the next several years as per Appendix III
   - Two transformers, AT9442 and 1-3296, may need to be replaced over the next couple of years. Note, however, that both these transformers are missing age data, had a low data availability index and they have a lowered health index when oil quality (a maintainable condition) is removed from the calculation.
   - 3 Joselyn Reclosers need to be replaced over the next couple of years

4. Replace assets in the Asset Groups C, D, E, H and the remaining assets in the Group G only when they fail unless specific defects indicating imminent failure are noticed during routine inspections, such as foot patrols.

5. HCHI maintenance practices, particularly since there is a plan to further develop inspection and maintenance programs, are compliant with the DSC requirements and are well suited for the geographical area served by this LDC.

Appendix I HEALTH INDEX METHODOLOGY FOR DISTRIBUTION STATION TRANSFORMERS

AI-1 Distribution Station Transformers Health Index Formulation

Table AI-1 Distribution Station Transformers Health Index

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Insulation	6	4
2	Cooling	2	4
3	Sealing & connection	3	4
4	Reliability	3	4

Table AI-1.1 Distribution Station Transformers Insulation (m=1)

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Oil quality	Table AI-2.2	8	4
2	Oil DGA	Table AI-2.3	10	4
3	Winding Doble	Table AI-2.4	10	4

Table AI-1.2 Distribution Station Transformers Cooling (m=2)

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Temperature	Table AI-2.1	10	4

Table AI-1.3 Distribution Station Transformers Sealing and Connections (m=3)

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Tank oil leak	Table AI-2.1	2	4
2	Conservator oil level	Table AI-2.1	2	4
3	Grounding	Table AI-2.1	1	4
4	IR thermography	Table AI-2.1	10	4

Table AI-1.4 Distribution Station Transformers Reliability (m=4)

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Loading	Table AI-2.6	10	4
2	Age	Table AI-2.5	6	4

AI-2 Distribution Station Transformers Condition Criteria

Table AI-2.1 Distribution Station Transformers Routine Inspection

Condition Rating	CPF	Condition Description
A	4	No "Not_OK" findings in past year
B	3	1 "Not_OK" work order in past year
C	2	2 "Not_OK" findings in past year
D	1	3 "Not_OK" findings in past year
E	0	> 3 "Not_OK" findings in past year

Table AI-2.2 Distribution Station Transformers Oil Quality Test

Condition Rating	CPF	Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
Moisture PPM (T °C Corrected) (From DGA test)	<=20	<=30	<=40	>40	4
Dielectric Str. kV D877	>40	>30	>20	Less than 20	3
IFT dynes/cm 230 kV ≤U	>32	25-32	20-25	Less than 20	2 *
IFT dynes/cm 69 kV <U< 230	>30	23-30	18-23	Less than 18	
IFT dynes/cm U ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color	Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number 230 kV ≤U	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
Acid Number 69 kV <U< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
Acid Number U ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* IFT Condition Criteria are selected based on the high side voltage level.
* Acid Number Condition Criteria are selected based on the high side voltage level

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, overall Factor = $\frac{\sum scorei \times Weighti}{48}$

Table AI-2.3 Distribution Station Transformers Oil DGA

Condition Rating *	CPF	Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

*In the case of a score other than A, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score B, 0.85 for score C, 0.75 for score D and 0.5 for score E.

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	1
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	1

and Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Table AI-2.4 Distribution Station Transformers Winding Doble Test

Condition Rating	CPF	Description
A	4	Values well within acceptable ranges; power factor less than 0.05%
B	3	Values close to acceptable ranges; power factor between 0.05 - .5%

Condition Rating	CPF	Description
C	2	Values exceed acceptable ranges; power factor between 0.5 – 1%.
D	1	Values considerably exceed acceptable levels; power factor between 1 - 2%
E	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

Table AI-2.5 Distribution Station Transformers Age

Condition Rating	CPF	Condition Description
A	4	0-19
B	3	20-39
C	2	40-59
D	1	60-69
E	0	>=70

Table AI-2.6 Distribution Station Transformers Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

Appendix II HEALTH INDEX METHODOLOGY FOR POLES

AII-1 Poles Health Index Formulation

Table AII-1 Poles Health Index

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Pole and cross arm	3	4
2	Pole accessories	1	4
3	Expert inputs	A multiplier for total HI	

Table AII-1.1 Poles and Cross Arms (m=1)

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Pole test results	Table AII-2.3	2	4
2	Pole condition	Table AII-2.1	1	4
3	Pole age	Table AII-2.4	3	4
4	Cross arm condition	Table AII-2.2	1	4

Table AII-1.2 Poles Accessories (m=2)

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Insulator	Table AII-2.2	1	4
2	Arrestor	Table AII-2.2	1	4
3	Switch	Table AII-2.2	1	4
4	Grounding	Table AII-2.2	1	4
5	Guying	Table AII-2.2	2	4

Table AII-1.3 Poles Expert Opinion

n	Sub-condition parameter	Multiplier Factor lookup table
1	Southern yellow pines issue	Table AII-2.5
2	Dunnsville 20 years poles issues	Table AII-2.5

AII-2 Pole Condition Criteria

Table AII-2.1 Poles Condition Based on Routine Inspections

Condition Rating	CPF	Condition Description
A	4	Okay
C	2	Spalling
D	1	Poor
E	0	Replace

Table AII-2.2 Poles Cross Arm and Accessories Condition

Condition Rating	CPF	Condition Description
A	4	Okay
C	2	Deteriorating (Rotting, cracked, loose etc)
E	0	Damaged/blown/broken

Table AII-2.3 Poles Test Results

Condition Rating	CPF	Condition Description
A	4	Re-test in 6 years
D	1	Replace in 2-3 years
E	0	Replace ASAP

Table AII-2.4 Poles Age

Condition Rating	CPF	Condition Description
A	4	0-19
B	3	20-39
C	2	40-49
E	0	>=50

Table AII-2.5 Poles Expert Opinion

Southern Yellow Pine poles		
Condition Rating	MF_1	Condition Description
A	0.9	Pole is of Southern yellow pine type
E	1	Pole is of other type
Dunnville 20 years poles		
Condition Rating	MF_2	Condition Description
A	0.9	Pole is in Dunnville region AND at its 20's
E	1	Pole is not in Dunnville region OR not at its 20's

Appendix III DETAILS OF HEALTH INDEX, AGE DISTRIBUTION, DATA AVAILABLITY AND CAPITAL REPLACEMENTS

AIII-A Asset Group A, Distribution Station Transformers

This was the only asset category for which replacement vs refurbishment options were considered. It was assumed that the cost of refurbishment is 50% of the replacement cost and that refurbishment is 75% effective.

Figure AIII-A.1 Asset Group A Health Index Distribution (Overall HI = 71%)

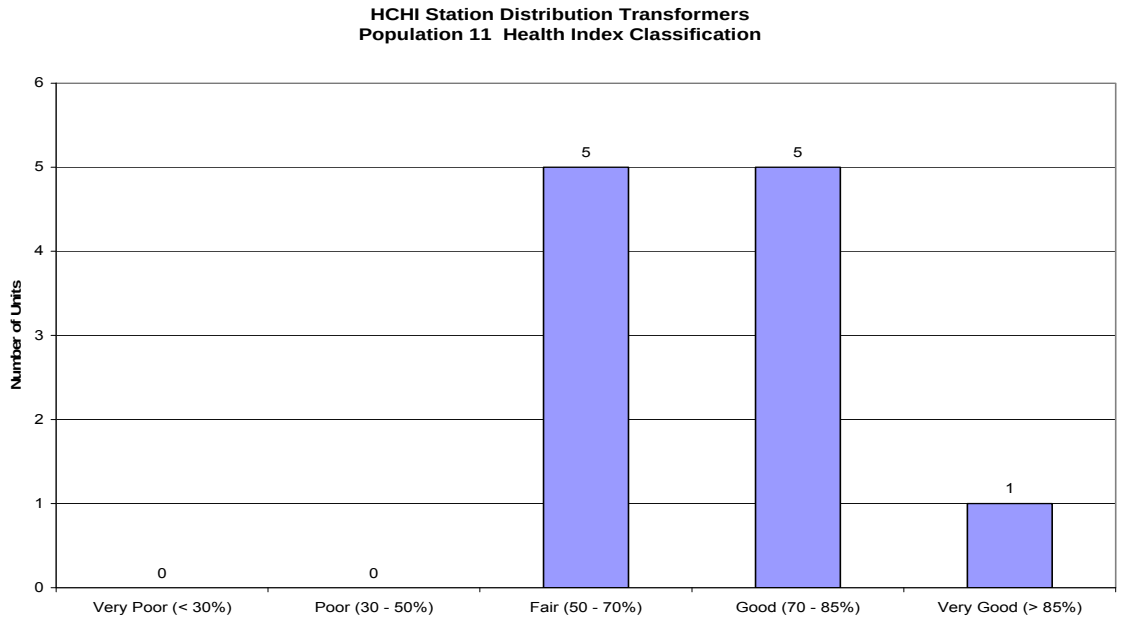


Figure AIII-A.2 Asset Group A Age Distribution

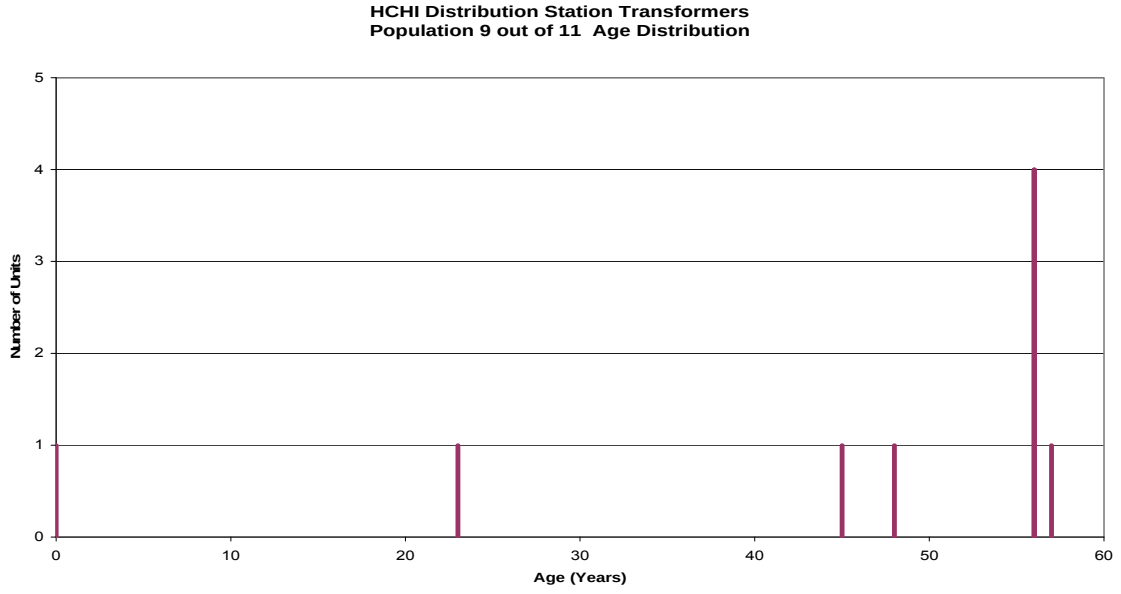


Figure AIII-A.3 Asset Group A Data Availability Indicator

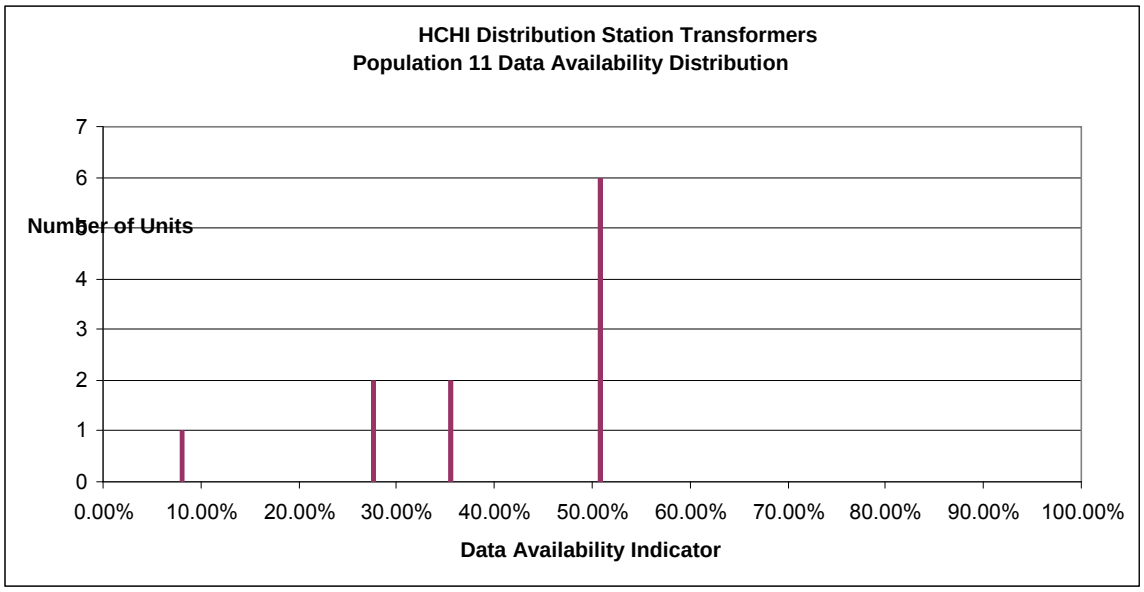


Figure AIII-A.4 Asset Group A Replacement Schedule

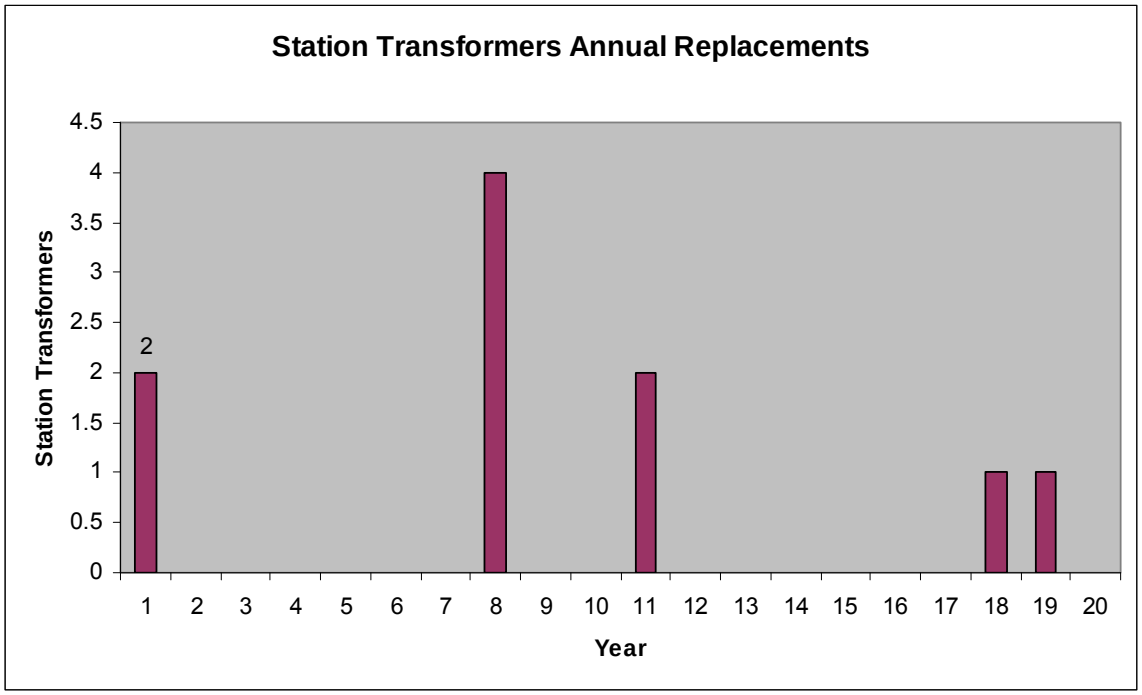
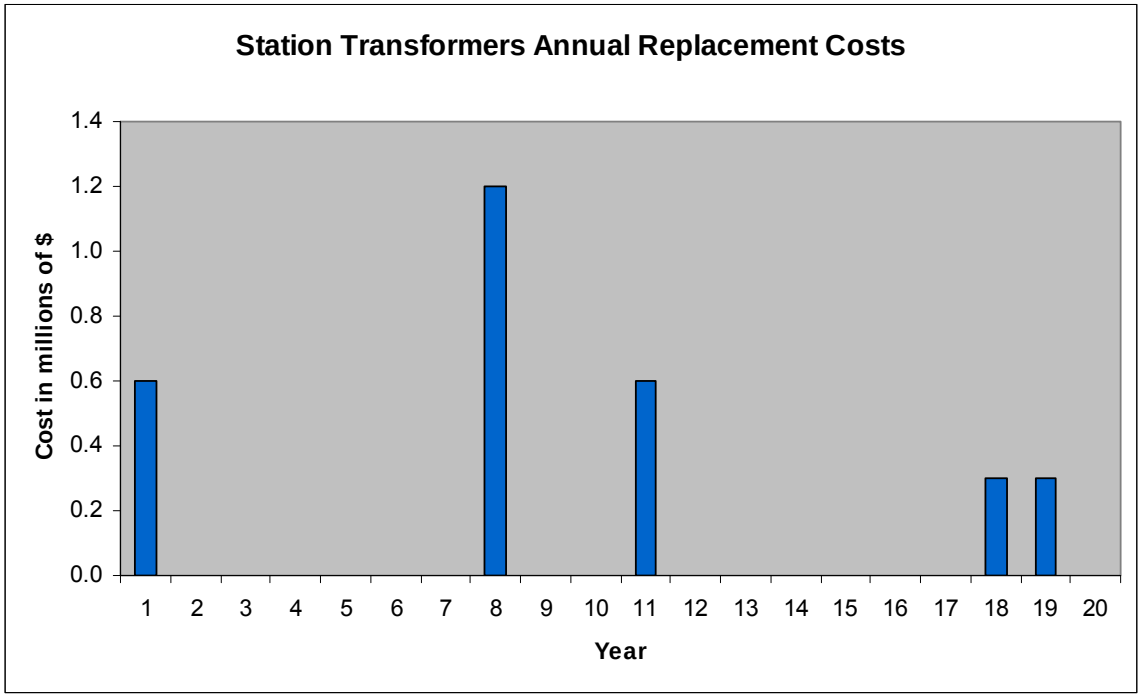


Table AIII-A4.5 Asset Group A Annual Replacements Cost



AIII-B Asset Group B, Air Blast Circuit Breakers

Age of both breakers was available. However, going forward it is essential to start collecting periodic test data for the breakers as specified in the Appendix IV of this report. Based on the breakers age none of them would have to be replaced in the next 20 years

Figure AIII-B.1 Asset Group B Health Index Distribution (Overall HI = 100%)

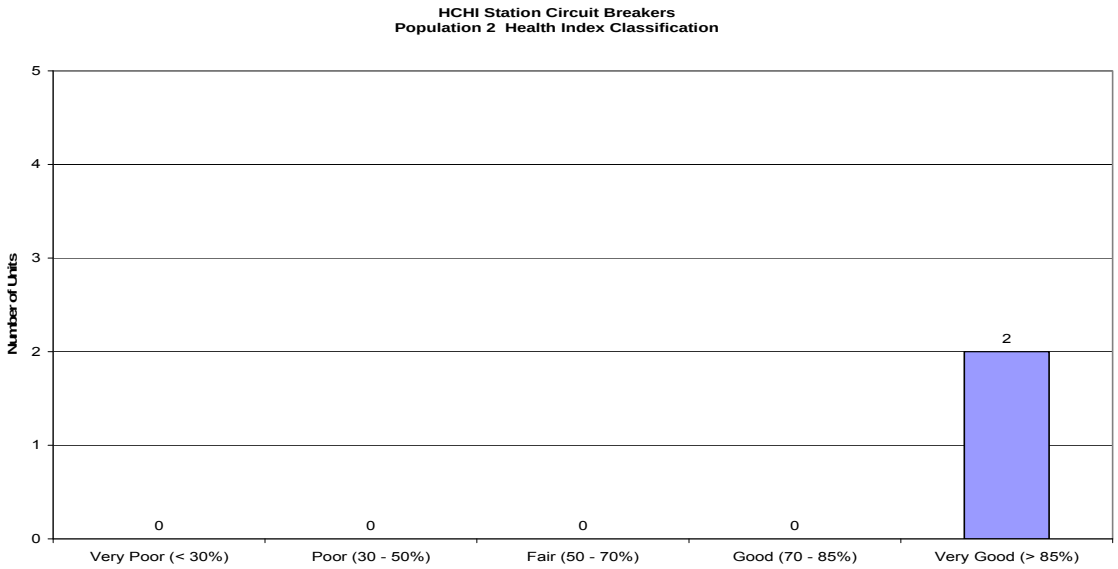
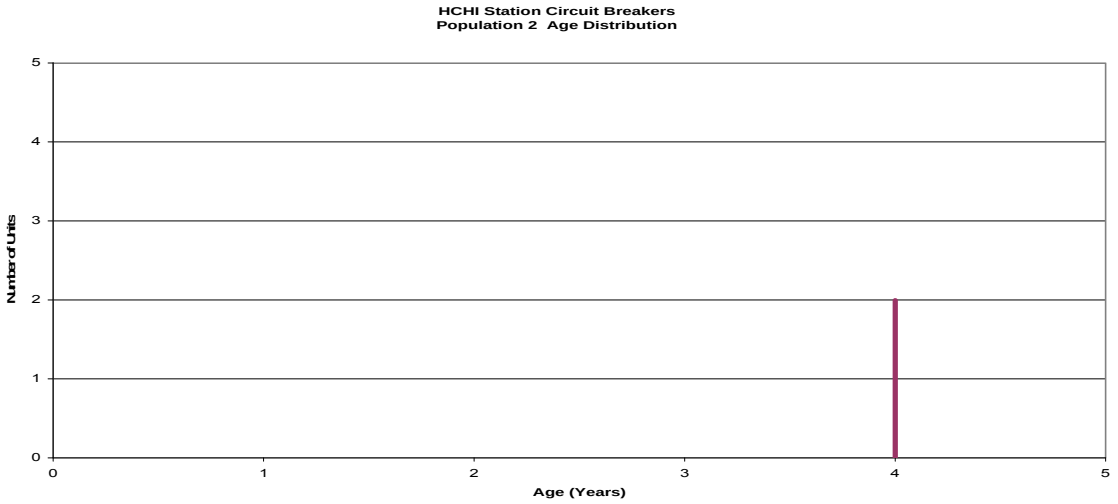


Figure AIII-B.2 Asset Group B Age Distribution



AIII-C Asset Group C, Pole Mounted Transformers

Age for only some of the pole mounted transformers was available. For the pole transformers without age available, their assumed age was matched with the pole age where possible. For the remaining transformers their age was extrapolated based on the assumption that the age distribution of the overall population of pole mounted transformers is the same as the overall age distribution of the poles. Health Index distribution was then based on the typical age-based industry experience. *Age information was available for 30% of the population.*

Figure AIII-C.1 Asset Group C Health Index Distribution (Overall HI = 74%)

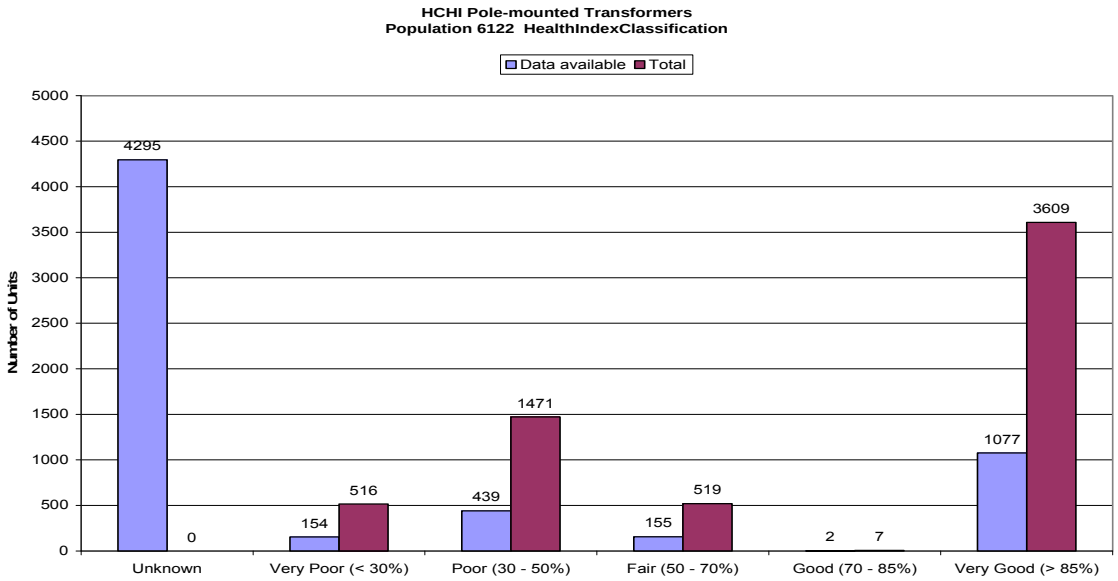


Figure AIII-C.2 Asset Group C Age Distribution

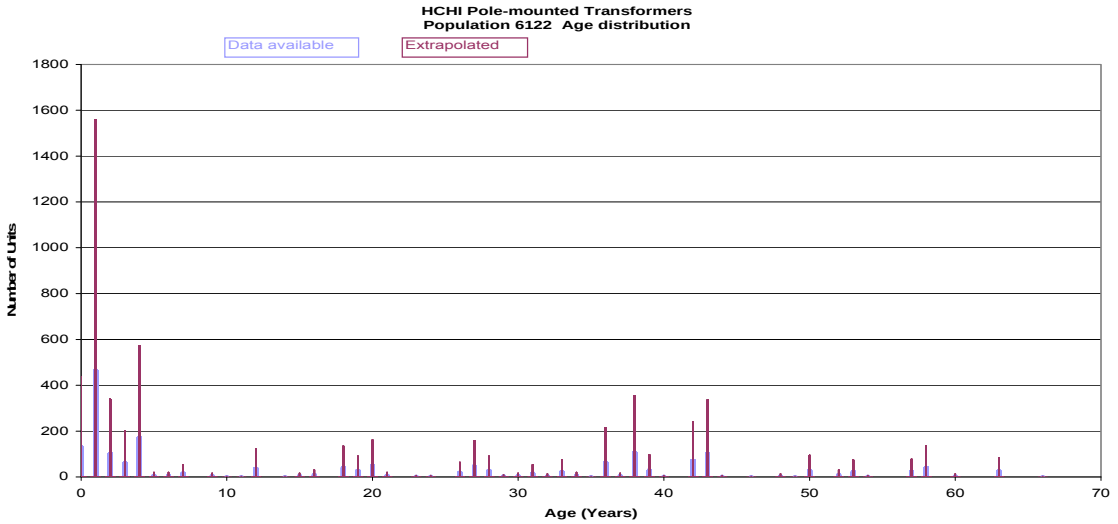


Figure AIII-C.4 Asset Group C Replacement Schedule

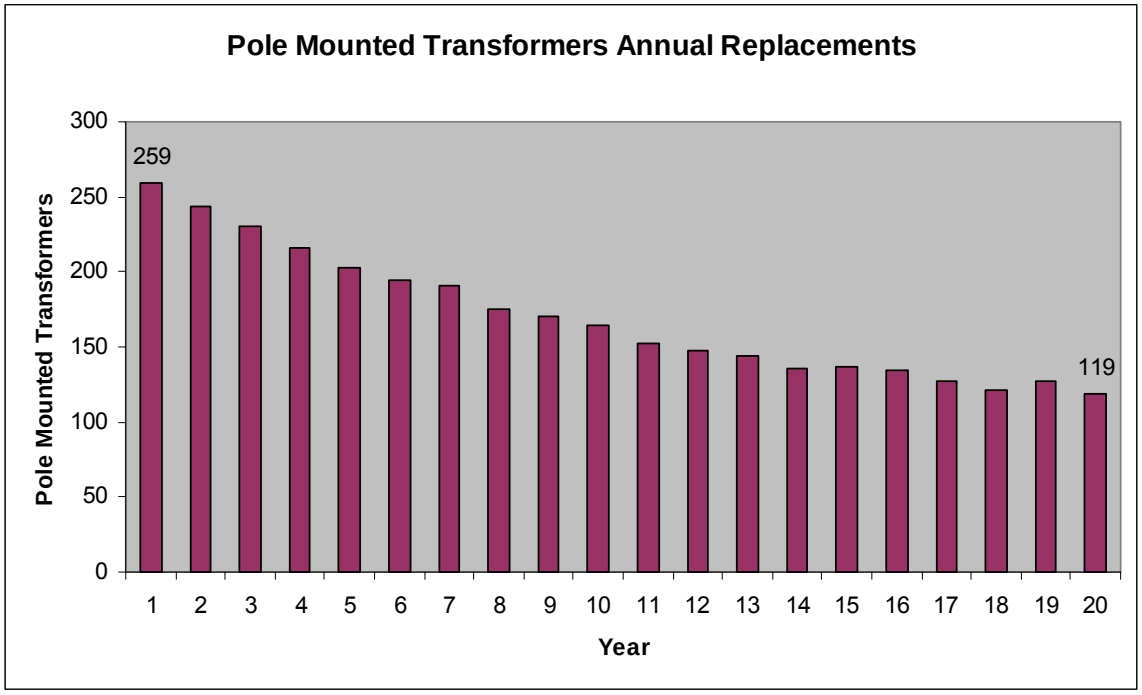
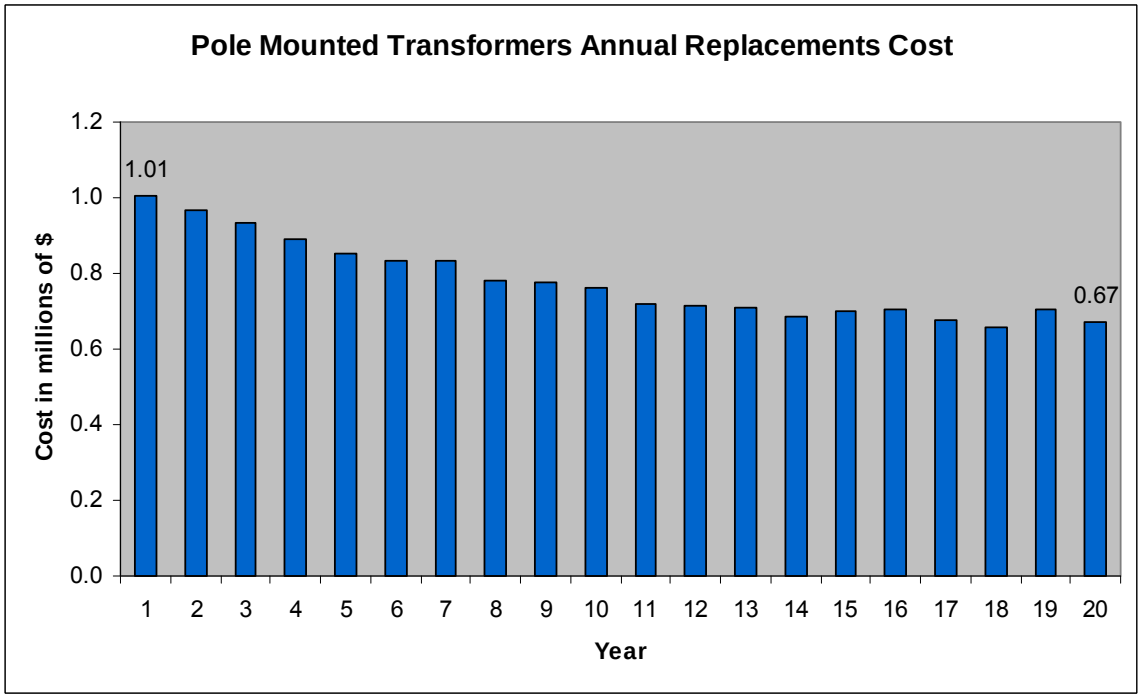


Figure AIII-C.5 Asset Group C Annual Replacements Cost



AIII-D Asset Group D Pad Mounted Transformers

Age for only some of the pad mounted transformers was available. For the remaining transformers their age was extrapolated based on the assumption that the age distribution of the overall population is the same as for the units with known age. Health Index distribution was then based on the typical age-based industry experience. *Age information was available for 82% of the population.*

Figure AIII-D.1 Asset Group D Health Index Distribution (Overall HI = 92%)

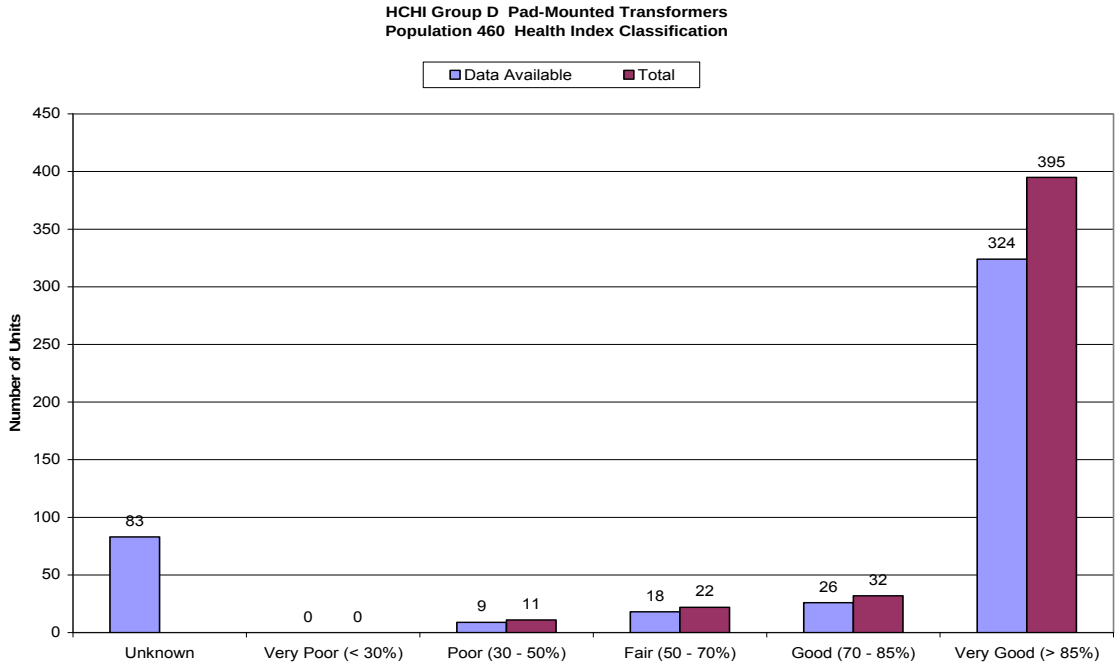


Figure AIII-D.2 Asset Group D Age Distribution

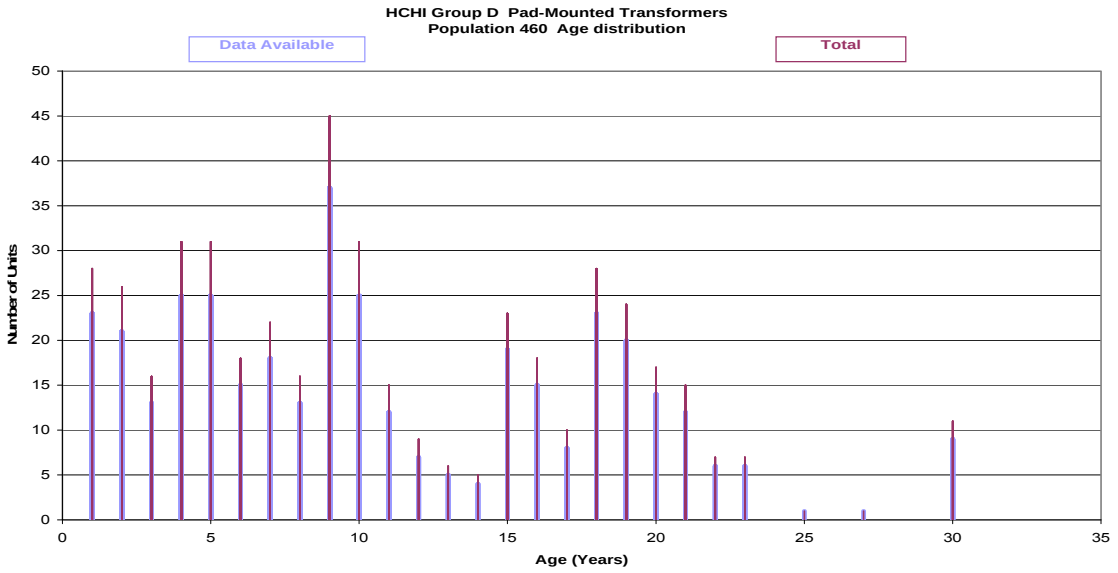


Figure AIII-D.4 Asset Group D Replacement Schedule

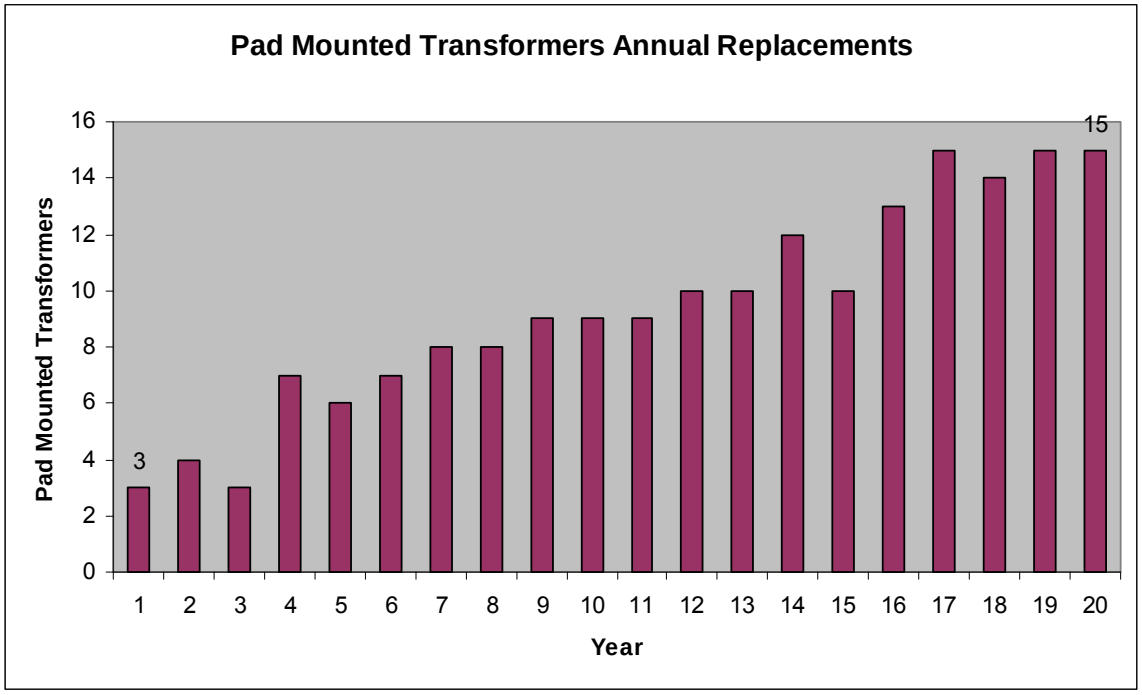
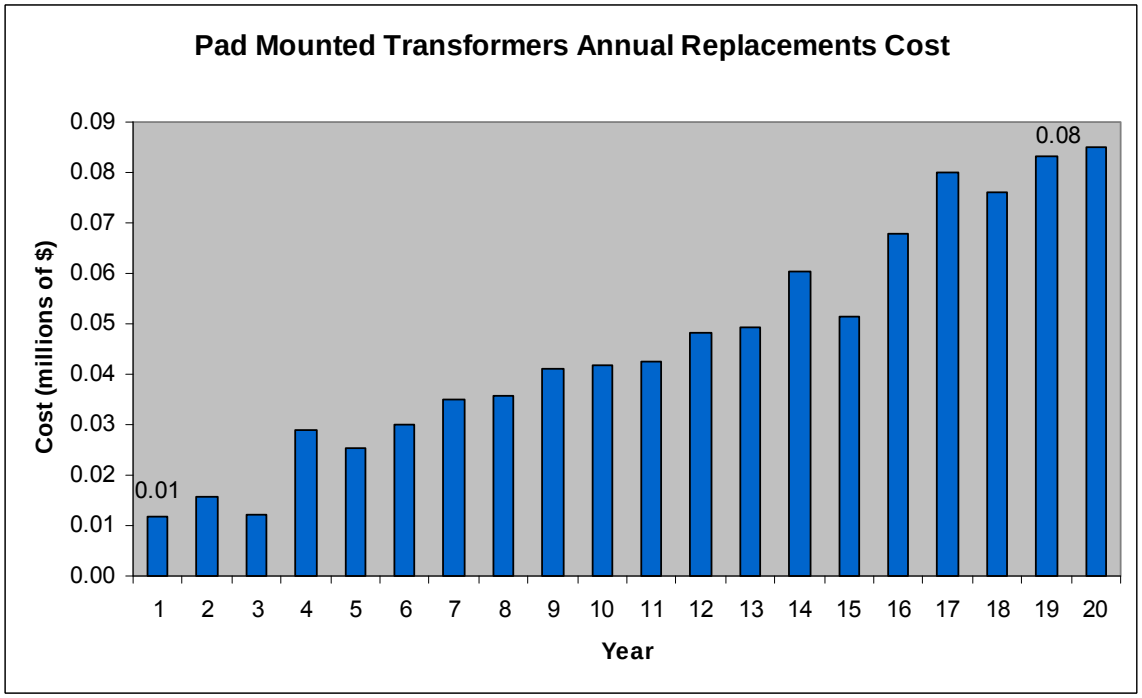


Figure AIII-D.5 Asset Group D Annual Replacements Cost



AIII-E Asset Group E, Vault Transformers

Health Index for the vault room transformers was based on their age and typical age-based industry experience. Age of all the vault transformers was available. Based on the vault transformers age none of them would have to be replaced in the next 20 years

Figure AIII-E.1 Asset Group E Health Index Distribution (Overall HI = 70%)

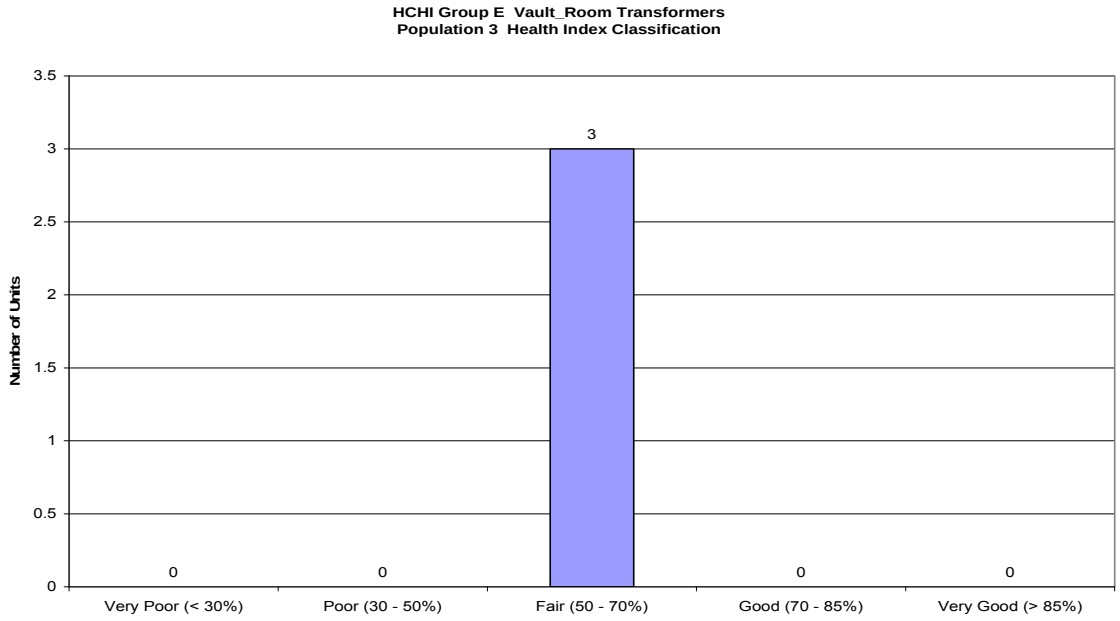
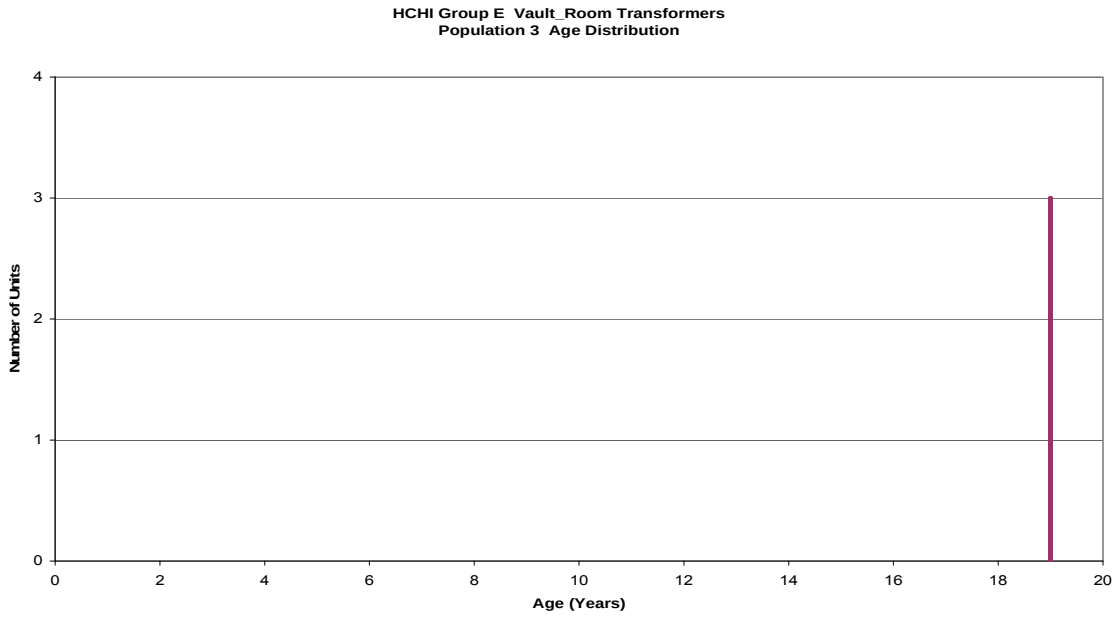


Figure AIII-E.1 Asset Group E Age Distribution



AIII-F Asset Group F, Poles

Figure AIII-F.1 Asset Group F Health Index Distribution (Overall HI = 69%)

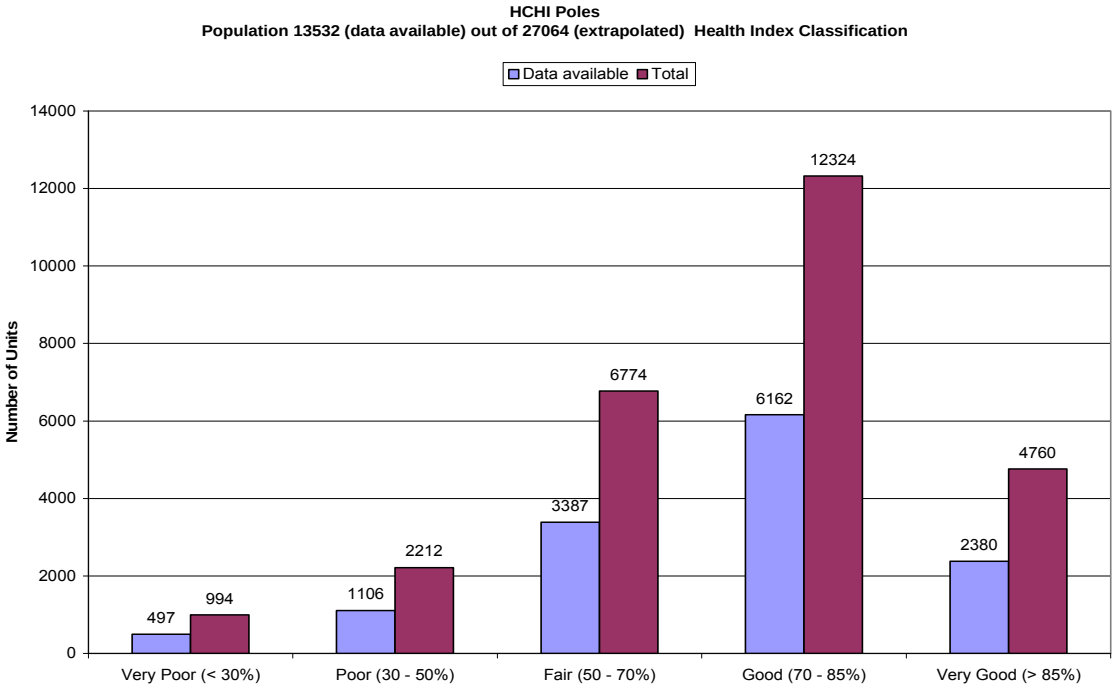


Figure AIII-F.2 Asset Group F Age Distribution

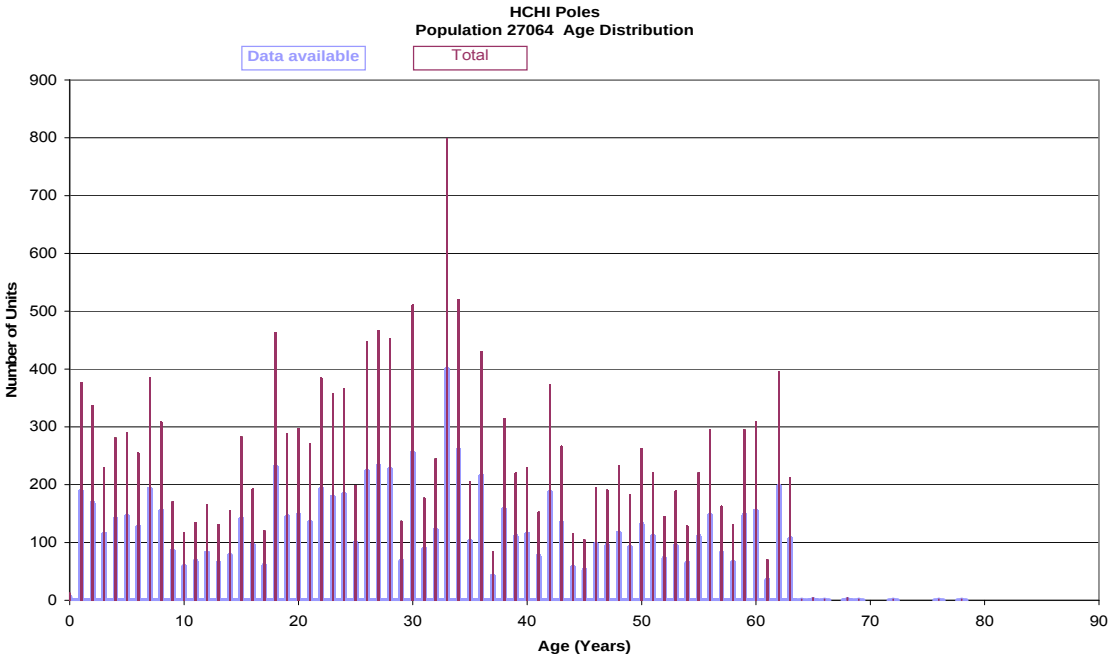


Figure AIII-F.3 Asset Group F Data Availability Indicator

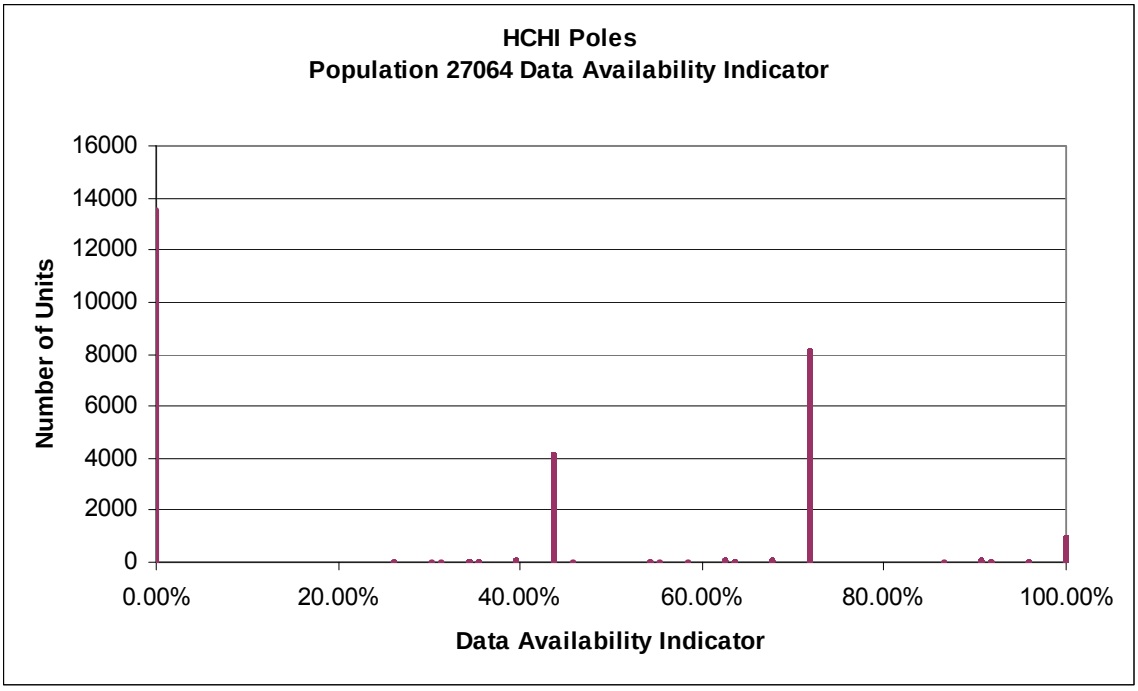


Figure AIII-F.4 Asset Group F Replacement Schedule

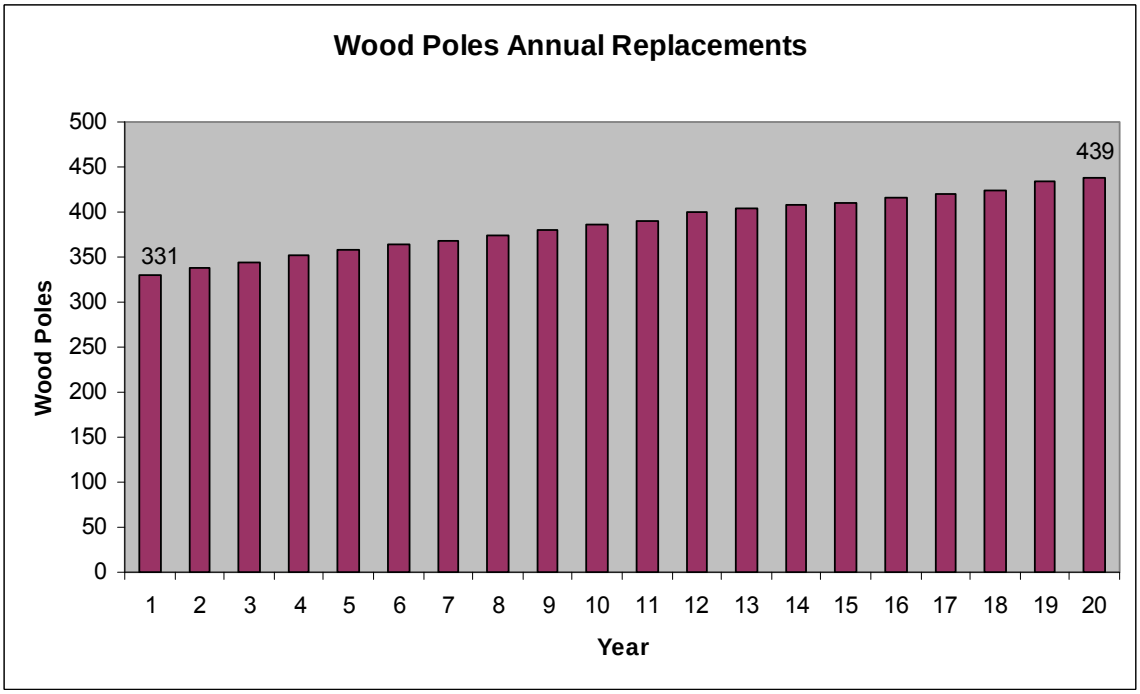
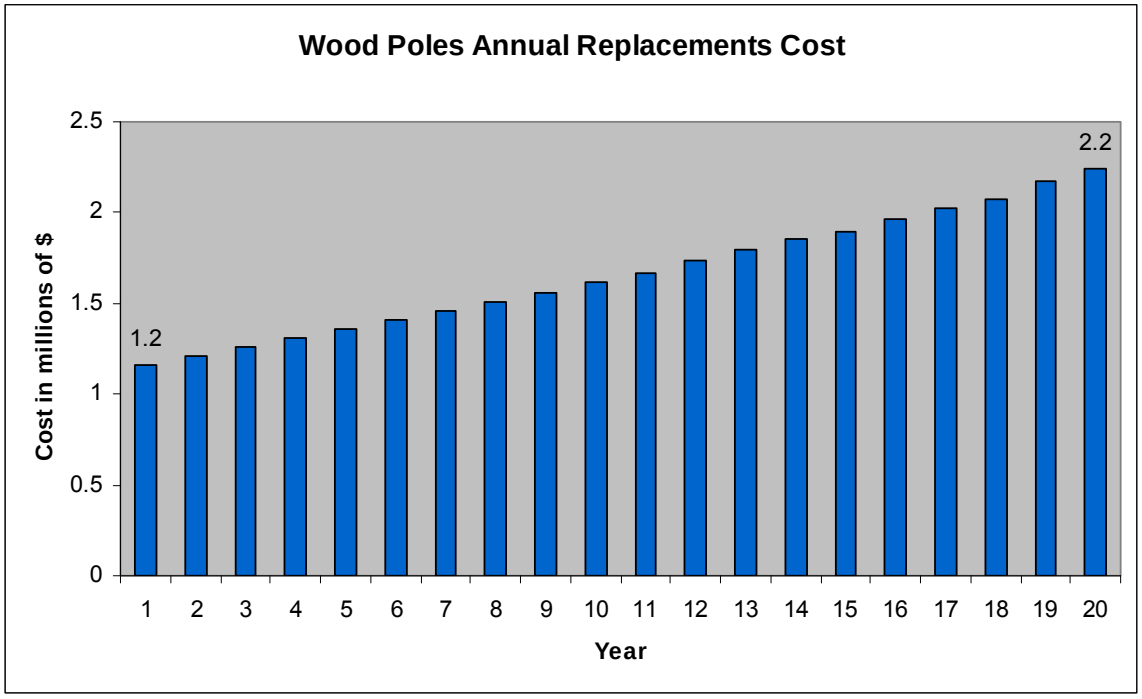


Table AIII-F4.5 Asset Group F Annual Replacements Cost



AIII-G Asset Group G, Gang-Operated Overhead Switches

Health Index for the Gang Operated Switches was based on their age vs typical age-based industry experience and field observations. Furthermore, based on the expert opinion, there were problems with older switches and switches over 30 years old were assumed to be in poor condition.

Infra-red thermography data were available for some of the switches but these are used to diagnose repairable defects rather than long-term condition deterioration. *Age information was available for 39% of the population.*

Figure AIII-G.1 Asset Group G Health Index Distribution (Overall HI = 83%)

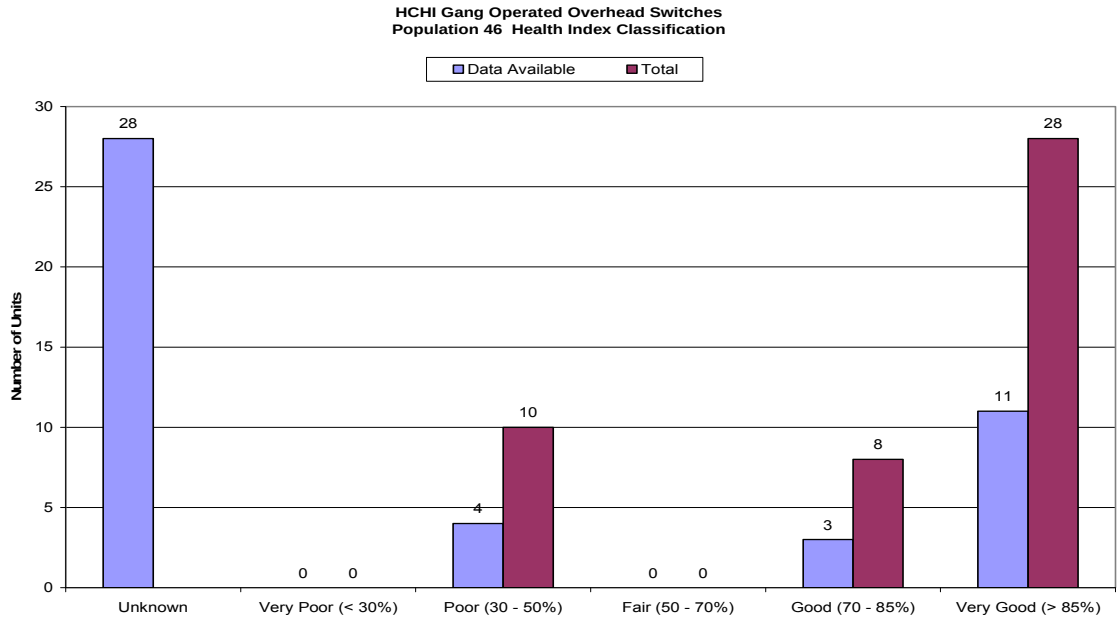


Figure AIII-G.2 Asset Group G Age Distribution

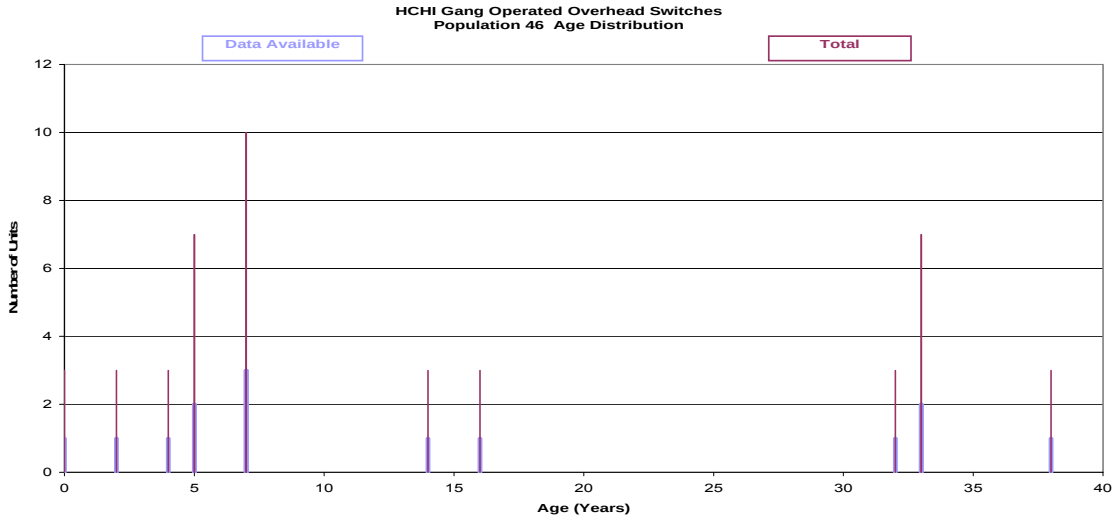


Figure AIII-G.4 Asset Group G Replacement Schedule

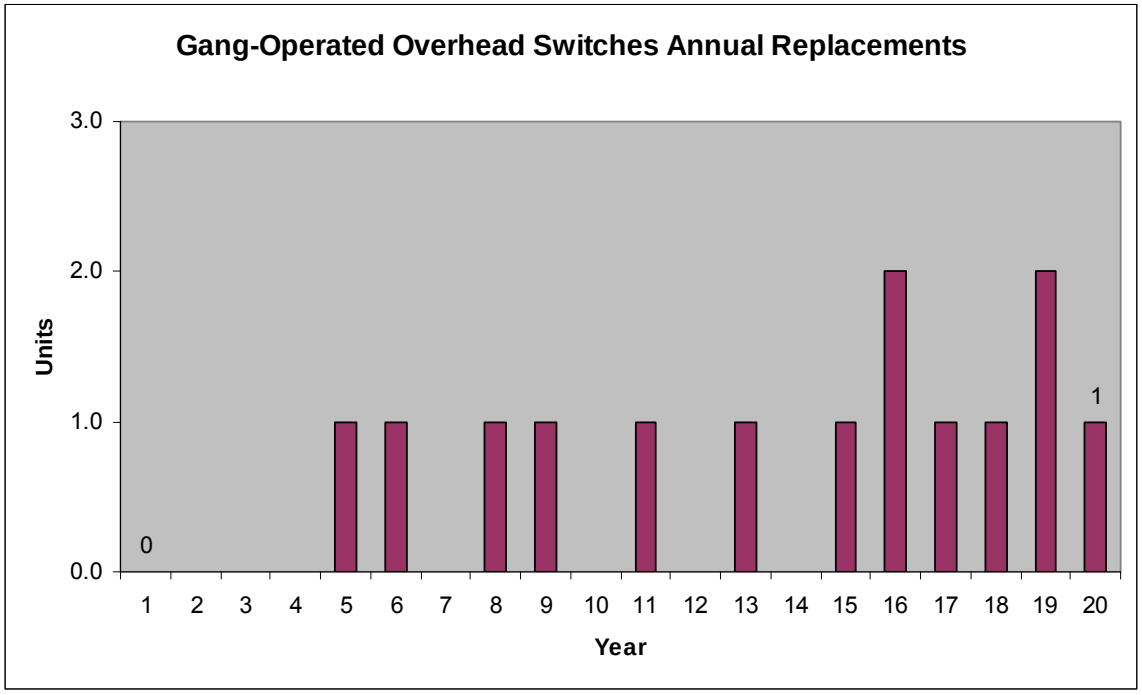
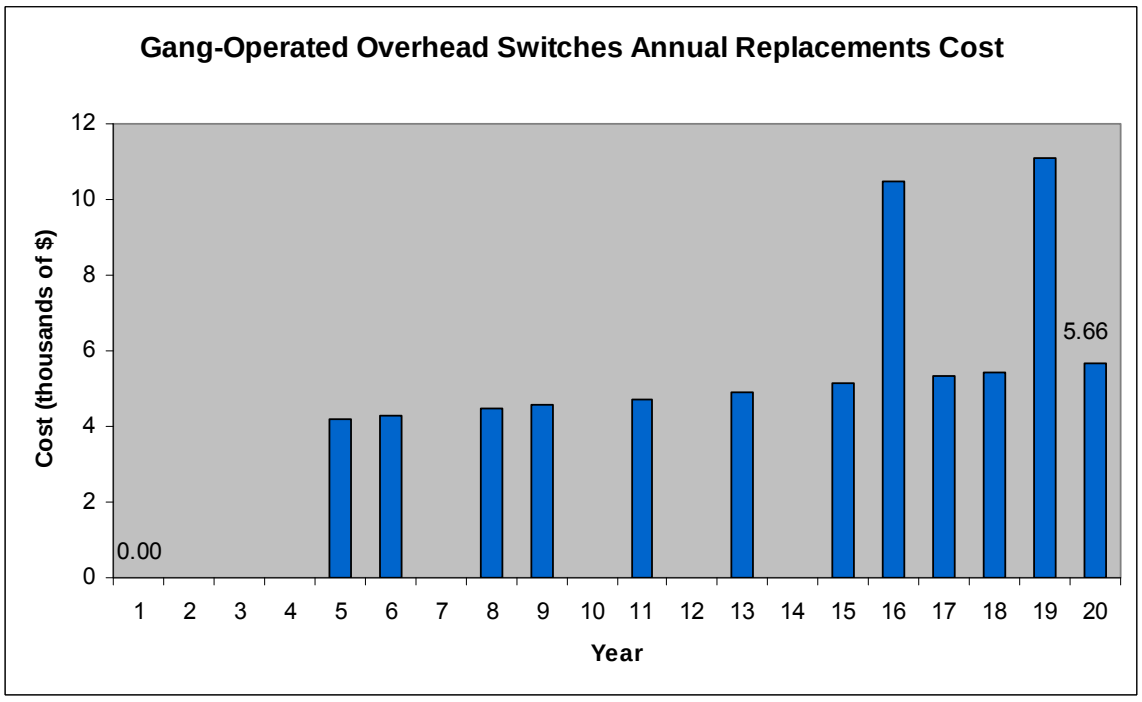


Figure AIII-G.5 Asset Group G Annual Replacements Cost



AIII-H Asset Group H, Pad Mounted Switch Gear

Field observations included 6 out of 10 Pad Mounted Switchgear and established ages of the 2 of them with one (at Cedar Street.) estimated to be installed in 2000. Combined with the age data provided by HCHI, age of 7 out of 10 units was known. Age was used to estimate Health Index based on the typical age-based industry experience. Based on the available data none of these units are recommended for replacement in the next 20 years. *Age information was available for 70% of the population.*

Figure AIII-H.1 Asset Group H Health Index Distribution (Overall HI = 84%)

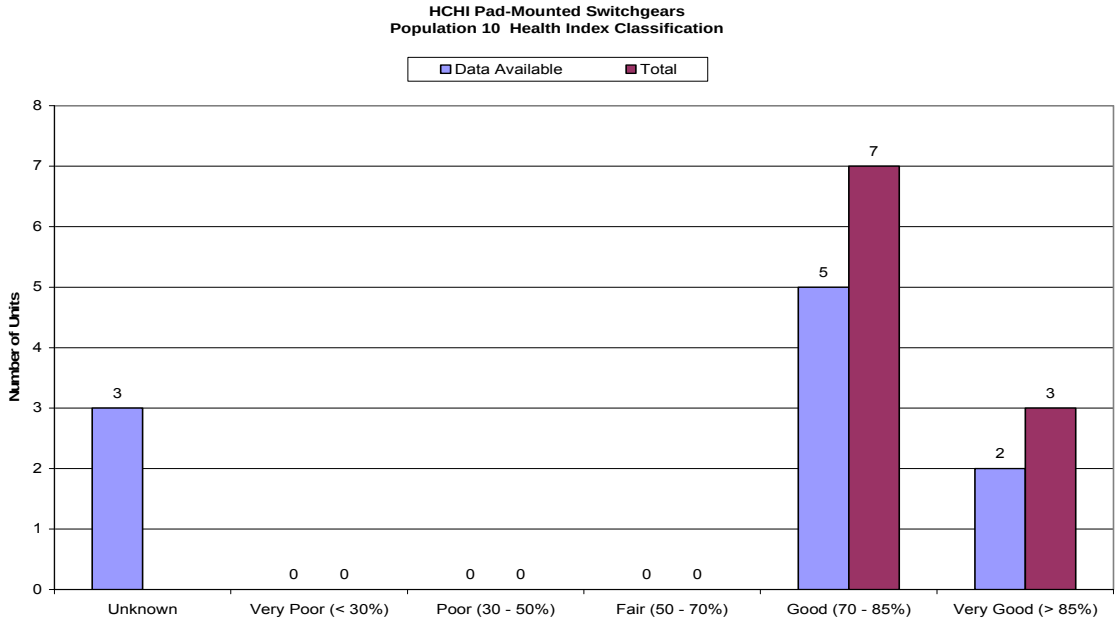
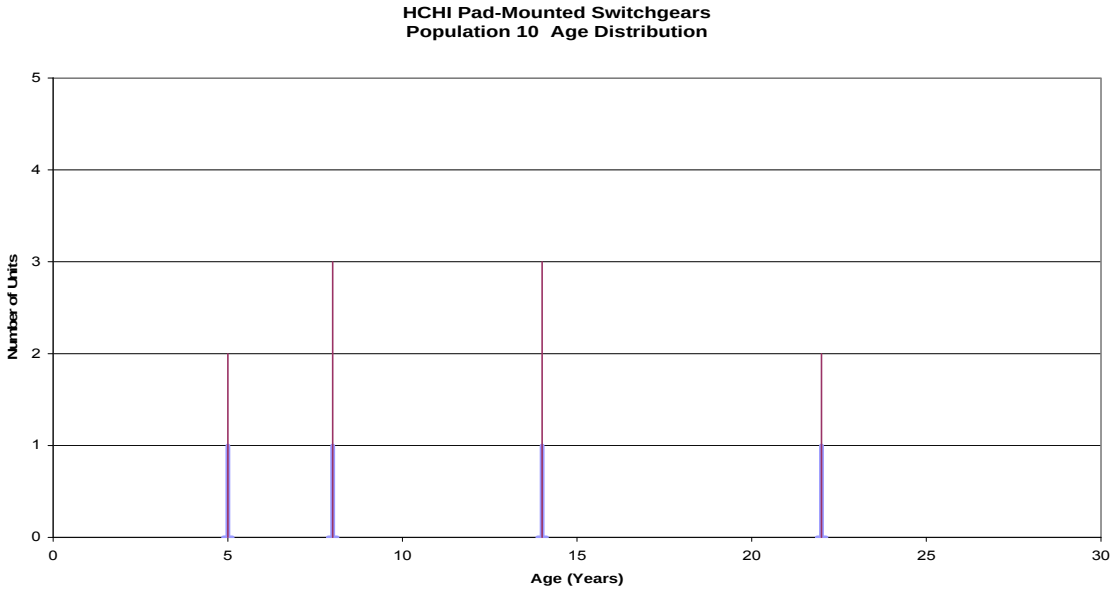


Figure AIII-H.1 Asset Group H Age Distribution



AIII-I Asset Group I, Underground XLPE Cable

Health Index for the primary Underground XLPE cables was based on their age derived as an average of the segments age and typical age-based industry experience. HCHI's system consists of 28 feeders with a total length of approximately 81 km. Health Index and Age distribution graphs are feeder based while the replacements charts are segment based. *Age information was available for 93% of the population.*

Figure AIII-I.1 Asset Group I Health Index Distribution (Overall HI = 89%)

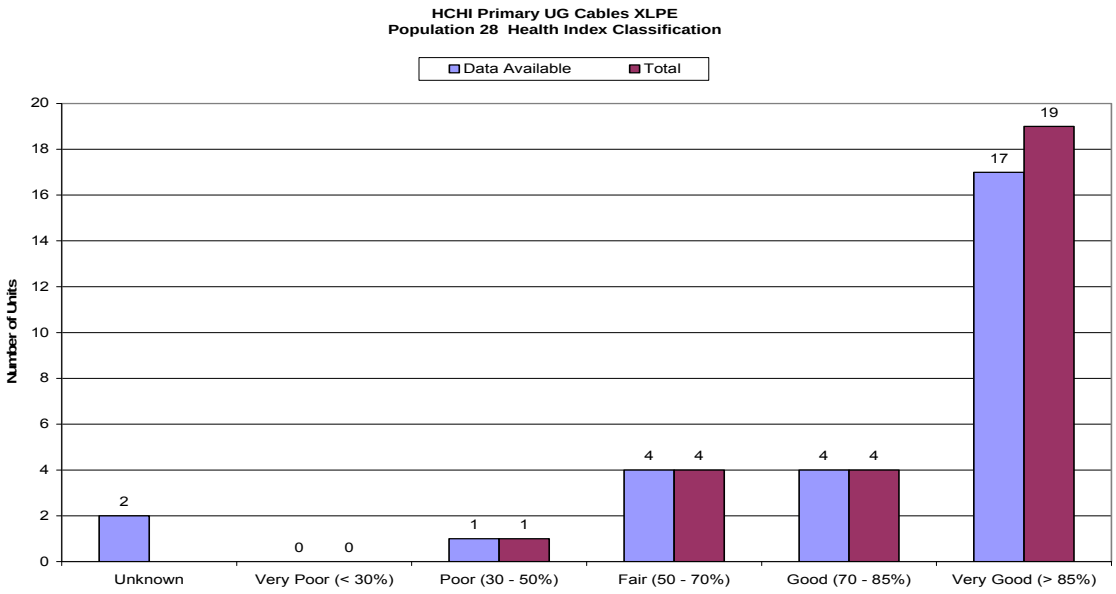


Figure AIII-I.2 Asset Group I Age Distribution

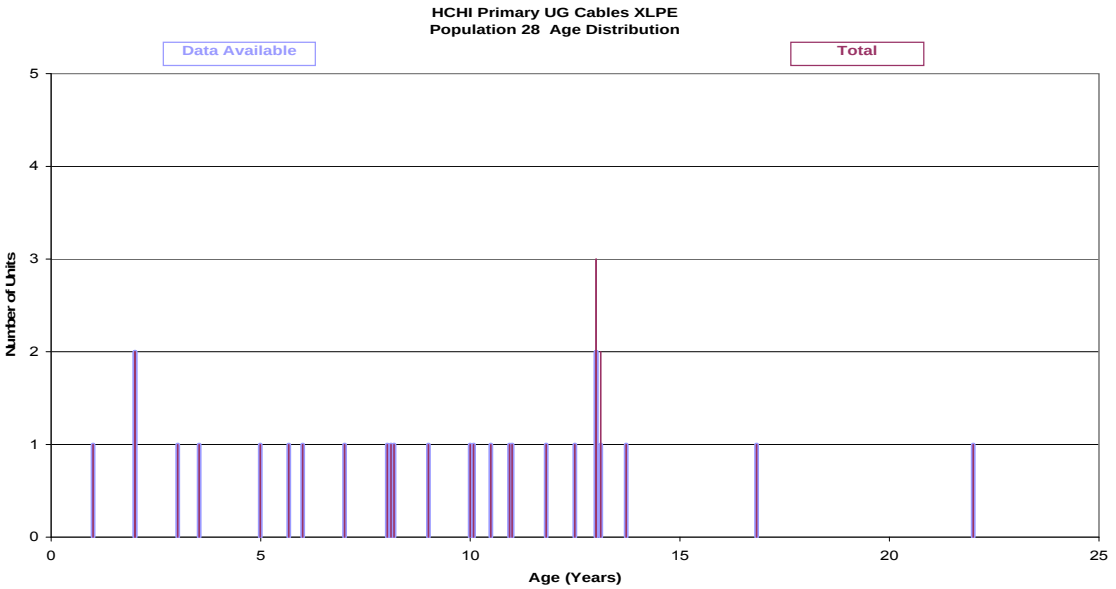


Figure AIII-I.4 Asset Group I Replacement Schedule

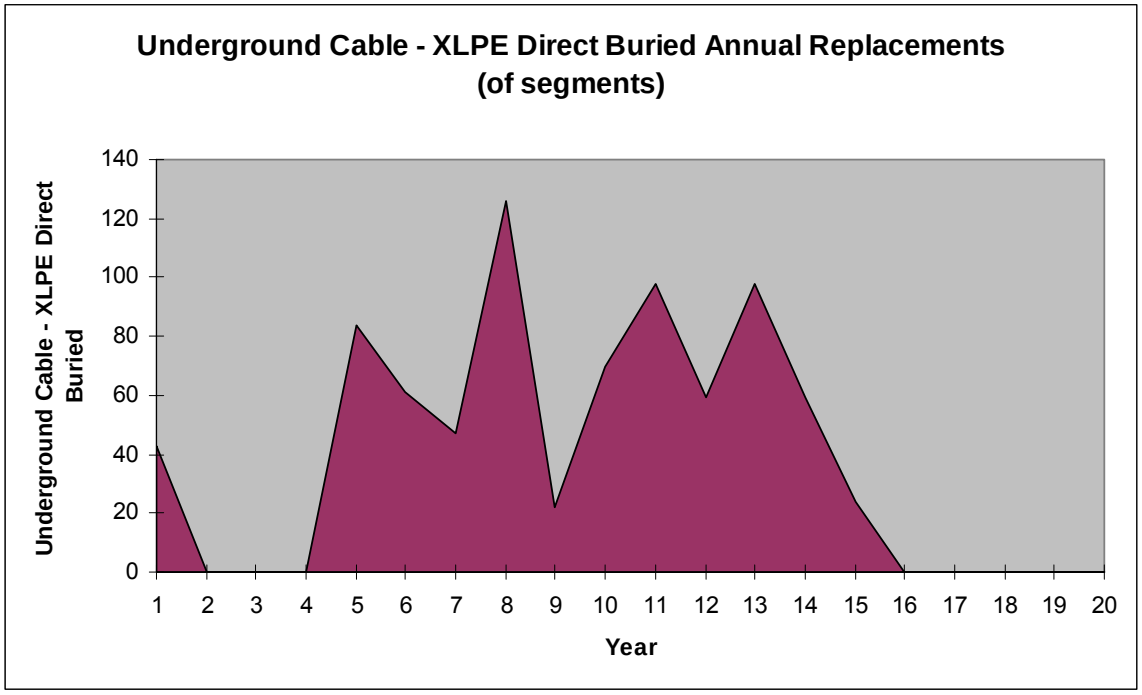
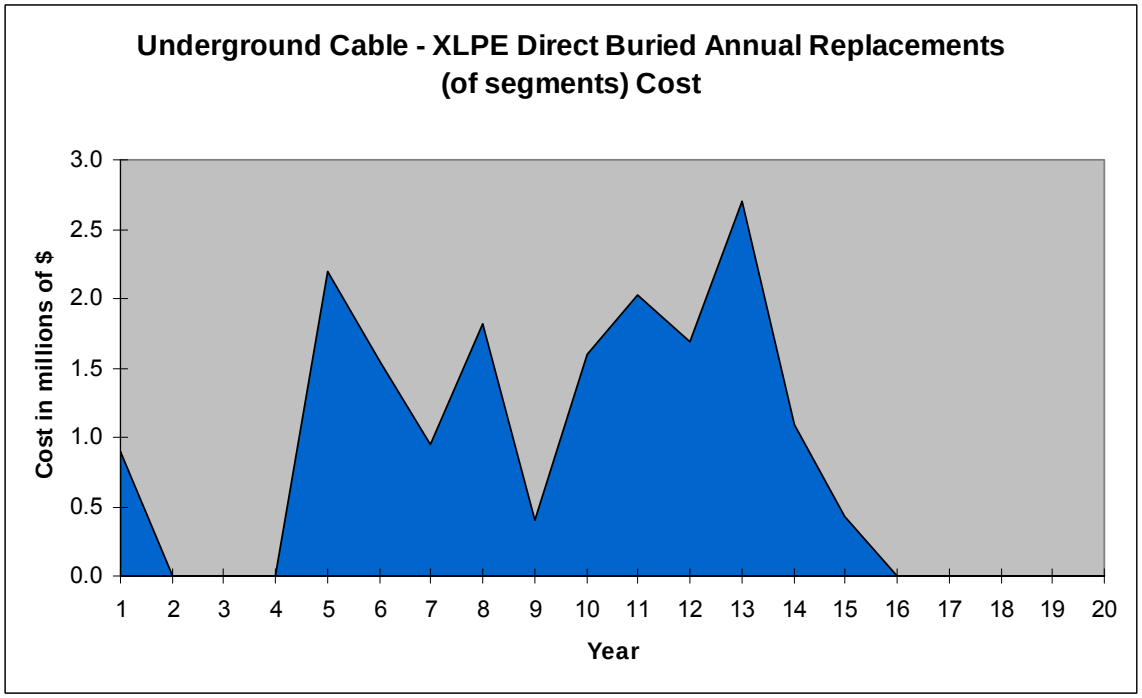


Figure AIII-I.5 Asset Group I Annual Replacements Cost



AIII-J Asset Group J, Overhead Reclosers

HCHI system has 7 reclosers with some of them manufactured by Joselyn. HCHI experienced some problems with them and plans to replace the remaining 3 Joselyn reclosers over the next couple of years. The remaining units are not recommended for replacement in the next 20 years. *Age information was available for 71% of the population.*

Figure AIII-J.1 Asset Group J Health Index Distribution (Overall HI = 67%)

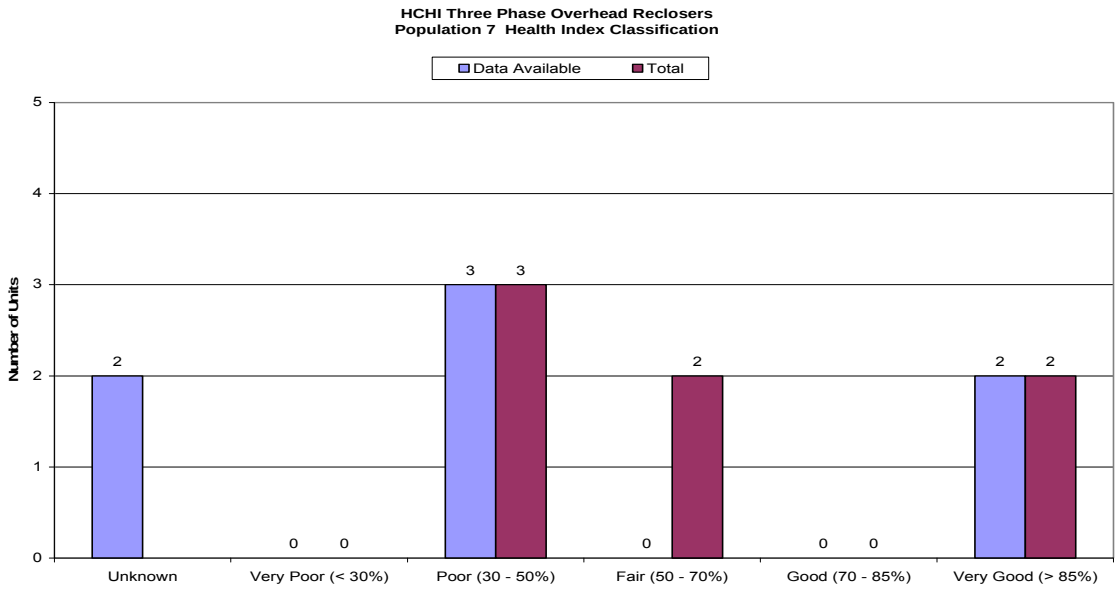


Figure AIII-J.2 Asset Group J Age Distribution

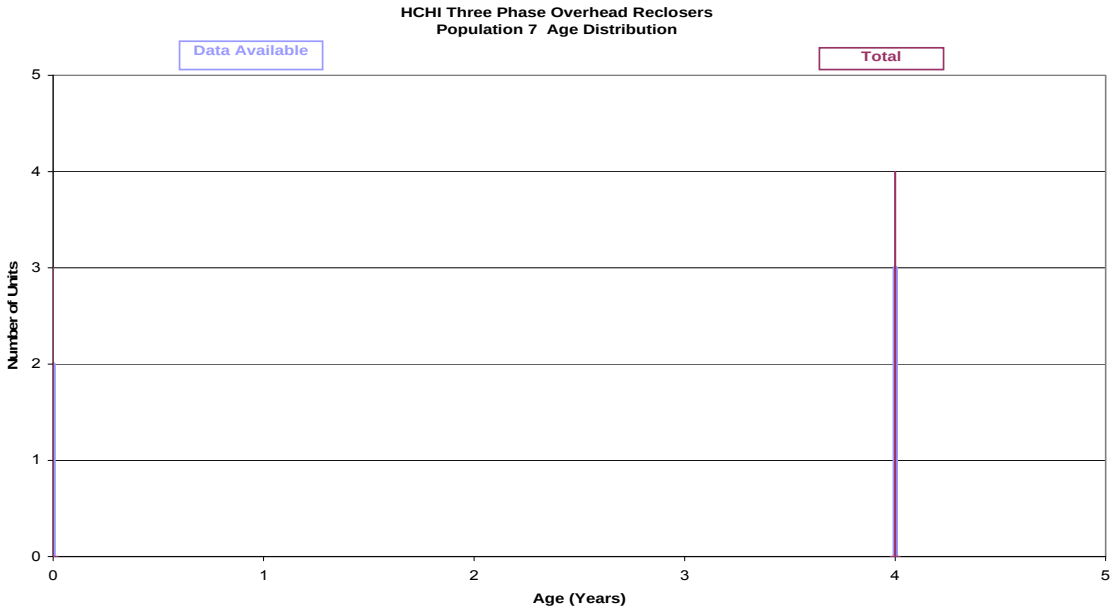


Figure AIII-J.4 Asset Group J Replacement Schedule

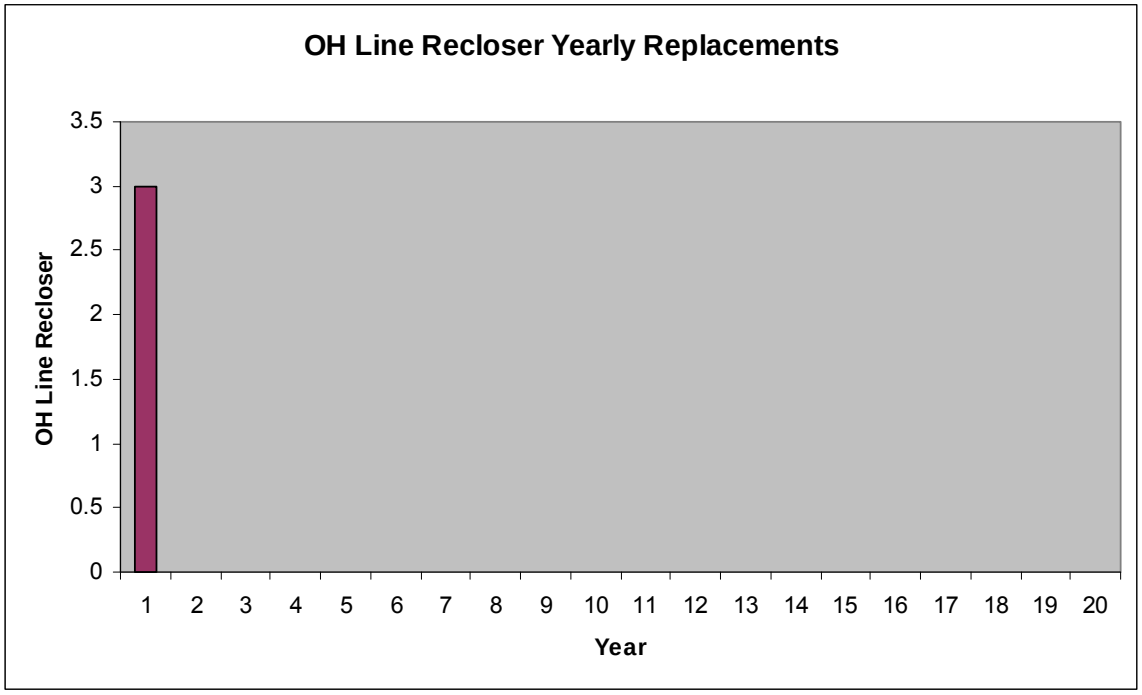
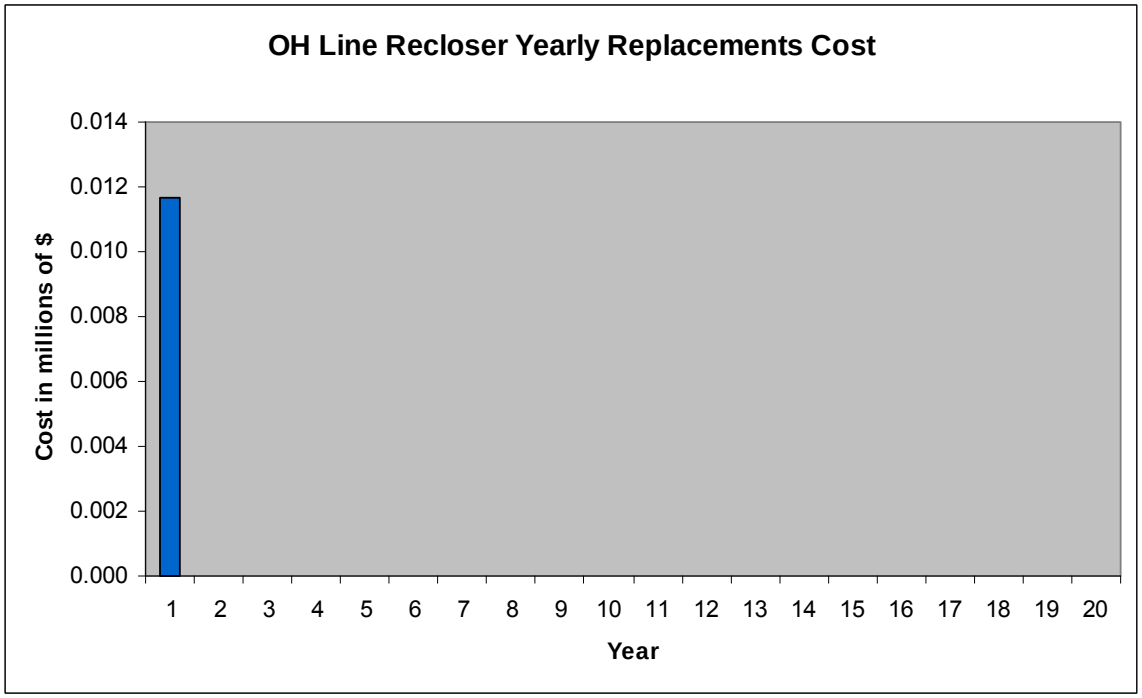


Figure AIII-J.5 Asset Group J Annual Replacements Cost



Appendix IV PRIORITIZED DATA GAPS CLOSURE

Tables below summarize data required for closing the data gaps. These requirements are prioritized based on their impact on the overall asset condition: P1 is for the highest impact, P2 for the medium impact and P3 for the lower impact.

In some cases the required data have been collected for all or some of the assets: these are included in the table and are highlighted in **bold with** no priority shown against them. It is assumed that the data collection for these condition parameters would continue for the remaining existing assets as well as for all new assets to be installed.

Table AIV-A Distribution Station Transformers

Type of Data Gap	Priority
Cooling/temperature (CM*)	P1
IR thermography (CM)	P1
Oil leak (CM)	P2
Oil level (CM)	P2
Loading	P1
Other CM	P3

***** Corrective Maintenance Incidents (usually measured as a number of work orders)

Table AIV-B Air Blast Breakers

Type of Data Gap		Priority
Manufacturer Information		
Install Date [Age(years)]		
Life time operating cycles		P2
Rated voltage & current		
Operating mechanism		
Operating mechanism type		
Electrical/mechanical test data (last reading)		
Static Contact resistance (uOhm)		
Arcing contact length (%)		P2
Closing	*Main contact closing time (cycle)*	P1
	Average closing velocity (ft/s)	P1
	Overtravel distance (inch)	P1
Tripping	*Main contact tripping time (cycle)*	P1
	Average tripping velocity (ft/s)	P1
Main contact trip-free time (cycle)		P1
Electrical test & on-site monitoring measurement (trend)		
Bushing power dissipation factor(%)		P2
CB Doble test power factor (%)		P2
Dewpoint measurement (degree)		P2
CB operating counter (cycle)		P2
Air pressure (normal/abnormal)		P2
Maintenance record (# corrective maintenance work orders in the past year)		
Leakage		P3
Moisture		P3
Lubrication		P1
Mechanism linkage		P1
CB contact		P2
Bushing		P3
Tank/vacuum bottle/arc chute		P3
Control/mechanism cabinet		P3
Supporting insulator		P3
Grading capacitor		P3
Shunt resistor for breaking		P3
Pre-inserted resistor for closing		P3
IR thermography detection		P2
System operation information		
Overall condition		
Fault level at CB		
CB loadings (monthly peaks in the past 5 years)		

Table AIV-C Pole Mounted Transformers

Type of Data Gap	Priority
Install date (age)	
Rated voltage & capacity	
Overall condition	
Manufacturer	P3
Loading (monthly peaks in the past 5 years)	P3

Table AIV-D Pad Mounted Transformers

Type of Data Gap	Priority
Install date (age)	
Rated voltage & capacity	
Corrosion	P3
IR thermography detection	P2
Overall condition	
Loading (monthly peaks in the past 5 years)	P3

Table AIV-E Vault Room Transformers

Type of Data Gap	Priority
Install date (age)	
Rated voltage & capacity	
Corrosion	P3
IR thermography detection	P2
Overall condition	
Loading (monthly peaks in the past 5 years)	P2

Table AIV-F Poles

Type of Data Gap	Priority
Age	
Pole test data (quantitative measurement)	
Pole type information (Southern yellow pine or not)	P2

Table AIV-G Gang Operated Overhead Switches

Type of Data Gap	Priority
Manufacturer Information	
Install date (age)	
Rated voltage & current	
Operating mechanism	
Operating mechanism type	P1
Maintenance record (# corrective maintenance work orders)	
Mechanism linkage	P1
Arc horn	P2
Switch contact	P2
Lubrication	P3
Support insulator	P3
Overall condition	P2
IR thermography	
System operation information	
Loading (monthly peaks in the past 5 years)	P2
Overall condition	

Table AIV-H Pad Mounted Switchgear

Type of Data Gap	Priority
Manufacturer Information	
Install Date [Age(years)]	
Life time operating cycles	P2
Rated voltage & current	
Contactor type	
Operating mechanism	
Operating mechanism	
On-site monitoring (trend)	
Protection alarm	P3
Maintenance record (# corrective maintenance work orders in the past year)	
Busbar	P2
Cabling	P3
Arc proof duct	P2
Lubrication	P1
Contactor	P1
CT & PT	P3
Grounding switch	P3
Metal enclosure	P3
IR thermography detection	
System operation information	
Overall condition	

Table AIV-I Underground XLPE Cable

Type of Data Gap	Priority
Manufacturer Information	
Install date (age)	
Rated voltage & current	P2
Maintenance record (# corrective maintenance work orders)	
Cable splice	P2
Gasket joint failure	P2
IR thermography	P1
System operation information	
Loading (monthly peaks in the past 5 years)	P2
Cable failure history	P1

Table AIV-J Overhead Reclosers

Type of Data Gap		Priority
Manufacturer Information		
Install Date [Age(years)]		
Life time operating cycles		P2
Rated voltage & current		
Operating mechanism		
Operating mechanism type		
Electrical/mechanical test data (last reading)		
Static Contact resistance (uOhm)		P1
Closing	*Main contact closing time (cycle)*	P1
	Average closing velocity (ft/s)	P1
	Overtravel distance (inch)	P1
Tripping	*Main contact tripping time (cycle)*	P1
	Average tripping velocity (ft/s)	P1
Main contact trip-free time (cycle)		P1
Reclosing circuit functionality		P1
Electrical test & on-site monitoring measurement (trend)		
CB Doble test power factor (%)		P2
CB operating counter (cycle)		P2
Maintenance record (# corrective maintenance work orders in the past year)		
Lubrication		P1
Mechanism linkage		P1
Vacuum bottle		P2
Control circuitry		P3
Control/mechanism cabinet		P3
Supporting insulator		P3
IR thermography detection		P2
System operation information		
Overall condition		
Fault level at CB		P3
CB loadings (monthly peak in the past 5 years)		P2

Appendix H - Discretionary Capital Projects 2009

Project Name – Central Lane Phase II Conversion - Dunnville

Prioritization Model:

		BEFORE			
	Project Name	**Central Lane Phase II Conversion - Dunnville**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Significant	Likely	38	9.5
0.2	Community Relations	Severe	Unlikely	51	10.2
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				24.7
		AFTER			
	Reliability/Performance	Small	Very Unlikely	1	0.3
	Community Relations				0.0
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					0.3
0.1	Business Efficiency	Severe	Likely	102	10.2
	Delta of Weighted Score plus Business Efficiency				34.7
	Cost of Project				$ 135,000
	Present Value of LV Savings				$ -
	Cost of Project minus LV PV				$ 135,000
	$/Weighted Score				$ 3,896

Discussion:

Business Value	Comments
Reliability/Performance	This area is currently fed from a step down transformer (27kv/4.2kv) and is a mixture of old and new assets. Converting to 27kv will eliminate the need for the 4.2kv equipment and standardize on 27kv. The upgrade will enhance reliability due to increased clearances and new equipment. The design also eliminates an inaccessible pole line on private property which will increase reliability as access is no longer an issue.
Community Relations	The area was partially rebuilt in the 1970's but was never completed. As a result there are a number of old poles in various conditions and some what would be considered temporary installations of equipment from old to new line. Eliminating the old assets will lessen the clutter of multiple poles on adjacent properties. The design also eliminates an inaccessible pole line on private property which will be viewed by the public as a positive move.
Safety	The risk of public safety will be improved by eliminating old assets. The risk to HCHI staff will be improved due to the elimination of temporary installations.
Regulatory Interference	No impact.
Environmental Stewardship	No impact.
Business Efficiency	The engineering design is complete.

Project Name – Moulton-Sherbrooke & Rattlesnake Conversion - Dunnville

Prioritization Model:

		BEFORE			
	Project Name	**Moulton Sherbrooke Townline - Rattlesnake Conv**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Significant	Most Likely	68	17.0
0.2	Community Relations	Severe	Unlikely	51	10.2
0.25	Safety	Severe	Very Likely	153	38.3
0.1	Regulatory Interference	Small	Unlikely	3	0.3
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				65.8
		AFTER			
	Reliability/Performance				0.0
	Community Relations				0.0
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					0.0
0.1	Business Efficiency	Severe	Likely	102	10.2
	Delta of Weighted Score plus Business Efficiency				76.0
	Cost of Project				$ 148,000
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 148,000
	$/Weighted Score				1949

Discussion:

Business Value	Comments
Reliability/Performance	This area has been subject to low voltage over the last two years. The feeder has a large phase to phase loading imbalance which cannot be corrected due to the layout of the distribution system. Low voltage occurs at peak loading during the summer peaks of June, July, and August. Converting the area will eliminate the imbalance on the 8.3kv F3 feeder from Dunnville DS and correct the low voltage.
Community Relations	Will eliminate low voltage complaints.
Safety	Low voltage complaints always require intervention by HCHI field staff. Corrective actions usually involve changing transformer taps or reconfiguring the circuits temporarily to improve voltage. Eliminating the need to take corrective action will remove the risk of an incident.
Regulatory Interference	During low voltage periods it is conceivable that the Electrical Safety Authority could intervene to order HCHI to take corrective actions to improve the voltage. Taking a proactive approach reduces the risk of intervention.
Environmental Stewardship	No impact.
Business Efficiency	The engineering design is complete.

Project Name – Lakeshore Road Re-Build – Melville Lane Area

Prioritization Model:

		BEFORE			
	Project Name	**Lakeshore Road Rebuild (Melville Lane)**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Significant	Very Likely	56	14.0
0.2	Community Relations				0.0
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship	Severe	Unlikely	51	5.1
	Sub Total of Weighted Score				24.1
			AFTER		
	Reliability/Performance				0.0
	Community Relations	Moderate	Likely	14	2.8
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship	Severe	Very Unlikely	20	2.0
					4.8
0.1	Business Efficiency	Moderate	Likely	14	1.4
	Delta of Weighted Score plus Business Efficiency				20.7
	Cost of Project				$ 346,500
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 346,500
	$/Weighted Score				16739

Discussion:

The Lake Erie shoreline is home to many single property cottages and clusters of cottages with privately owned roads or lanes. Traditionally this area was inhabited seasonally, but in recent years there is a trend for developing all season properties. This area runs along the lake for approximately 60 km. The age of the assets in these areas is 1950-60's vintage and much of it is installed in rear lots away from the travelled portion of the road. Due to its age the area is very well established with many encumbrances to our pole lines such as sheds, clothes lines, parked boats & cars, building materials, etc. This makes maintenance and restoration very inefficient and costly.

HCHI recognizes that these assets are approaching the end of life cycle and due to the length of line along the lake asset replacement will need to be a long term program likely exceeding twenty (20) years in time. The basic strategy encompasses the following concepts:

a) Relocate primary and where possible secondary to roadways and laneways;
b) Utilize underground assets where necessary;

c) Minimize the impact to the customer where new assets are installed where there was none before.

The above project is the first of many and in some ways is a pilot project for the rest of the asset re-development along the lake.

Business Value	Comments
Reliability/Performance	As the age of the assets increases the reliability will decrease with time. Access to rear lot always increases restoration times. Redeveloping will increase reliability and decrease restoration time.
Community Relations	There will be a trade-off with increased reliability and the location of assets. Relocating assets from the rear lot and placing them on roadways will likely be opposed by numerous property owners.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards) and relocating from the rear lot. The risk to HCHI staff will be reduced due to better access, increased clearances of new designs, and elimination of deteriorated plant.
Regulatory	No impact
Interference	
Environmental Stewardship	The close proximity to the lake makes a transformer oil spill a sensitive issue. Eliminating old plant will decrease the risk.
Business Efficiency	The engineering design is in a preliminary state where the specific design details have yet to be decided upon.

Project Name – Eliminate Selkirk North DS

Prioritization Model:

		BEFORE			
	Project Name	**Eliminate Selkirk North DS**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Significant	Likely	38	9.5
0.2	Community Relations				0.0
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship	Worst Case	Unlikely	139	13.9
	Sub Total of Weighted Score				28.4
		AFTER			
	Reliability/Performance	Small	Very Unlikely	1	0.3
	Community Relations				0.0
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					0.3
0.1	Business Efficiency	Moderate	Likely	14	1.4
	Delta of Weighted Score plus Business Efficiency				29.6
	Cost of Project				$ 295,000
	Present Value of LV Savings				$ 553,253
	Cost of Project minus LV PV				$ (258,253)
	$/Weighted Score				-8740

Discussion:

Business Value	Comments
Reliability/Performance	Selkirk North DS has station transformers built in 1952 which have exceeded their life cycle. In recent years faults occurring at this station have contributed to the deterioration of the transformer bushings. Rondar Inc. (an electrical service firm) has recommended the replacement of the bushings in the near future. Elimination of this station will increase reliability.
Community Relations	The existing station is in a residential area and disposing of the station will likely clear the way for more residential development consistent with the surrounding area. A positive step.
Safety	Elimination of assets at the end of their lifecycle will increase safety for the public and HCHI staff.
Regulatory Interference	No impact
Environmental Stewardship	A breach in the station transformer tanks could possibly lead to pollution in the Grand River which is 124 meters away. Elimination prevents this from happening.
Business Efficiency	The engineering design is in a preliminary state where the specific design details have yet to be decided upon.

Project Name – Purchase Hydro One F2 Feeder out of Argyle Distribution Station

Prioritization Model:

		BEFORE			
	Project Name	**Purchase HO Argyle DS F2 Feeder**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Moderate	Likely	14	3.5
0.2	Community Relations				0.0
0.25	Safety				0.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				3.5
		AFTER			
	Reliability/Performance	Small	Unlikely	3	0.8
	Community Relations				0.0
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					0.8
0.1	Business Efficiency	Worst Case	Likely	278	27.8
	Delta of Weighted Score plus Business Efficiency				30.6
	Cost of Project				$ 200,000
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 200,000
	$/Weighted Score				6547

Discussion:

Within the service territory of HCHI there are pole lines and circuits owned by Hydro One. These assets generally were retained by Hydro One after the sale of Hydro One assets to the LDC's in the late 1990's because they supplied power to Hydro One customers beyond HCHI's borders. This particular circuit is an 8.3kv circuit fed from Hydro One's Argyle DS.

In 2007 Hydro One informed HCHI that all IESO metering points between Hydro One and HCHI would not be brought up to current IESO standards. A solution was therefore required to either eliminate the metering point or change the type of billing to a retail account. In this case it was proposed that with little effort the metering point could be eliminated if Hydro One would sell its assets within HCHI's service territory and provide step down transformation at the border to accommodate Hydro One customers. The main benefit of this is the reduction of sub-transmission charges for use of their distribution equipment.

This purchase was approved by the OEB in February 2009.

Business Value	Comments
Reliability/Performance	Provides a path for HCHI to convert to 27kv in the future. Responsibility for maintenance and emergency response would change from HO to HCHI increasing the speed of the response due to local presence.
Community Relations	No impact
Safety	No coordination of emergency repairs would have to be made by HCHI which reduces the risk of an incident.
Regulatory Interference	No impact.
Environmental Stewardship	No impact.
Business Efficiency	This is strictly a purchase no design required.

Project Name – Construction of Line from Hagersville to Jarvis

Prioritization Model:

The prioritization model is not appropriate for this project because this is the remaining portion of a project started in 2007.

Discussion:

This project was budgeted in 2007 and 2008. The benefits are as follows:

a) Replace existing lines which were nearing end of life cycle.
b) Provides a 27.6kV tie between Caledonia TS and Jarvis TS where none existed before. This increases reliability because more circuit configurations are possible.
c) Eliminates SUB-TRANSMISSION charges from the 27M3 supplying Hagersville, from the 57M3 supplying Jarvis and the rural load between the communities of Jarvis and Hagersville. This has been calculated at $45,000 per year.
d) Eliminates the dependence on Hydro One to respond to emergency situations on feeders they own which supply HCHI customers (27M3 and 57M3).
e) New line construction increases the level of public safety due to increased clearances and assets which are in new condition.

Appendix I - Discretionary Capital Projects 2010

Project Name – Concessions 12, 13, 14, 15, 16, and 17 – Eliminate 57M3 Supply Points

Prioritization Model:

		BEFORE			
	Project Name	**Concessions 12 to 17 - Eliminate 57M3 Supply Points**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Moderate	Most Likely	25	6.3
0.2	Community Relations	Severe	Most Likely	184	36.8
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				48.1
		AFTER			
	Reliability/Performance	Small	Very Unlikely	3	0.8
	Community Relations	Moderate	Very Unlikely	3	0.6
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					1.4
0.1	Business Efficiency	Significant	Likely	38	3.8
	Delta of Weighted Score plus Business Efficiency				50.5
	Cost of Project				$ 160,000
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 160,000
	$/Weighted Score				3168

Discussion:

Within the service territory of HCHI there are pole lines and circuits owned by Hydro One. These assets generally were retained by Hydro One after the sale of Hydro One assets to the LDC's in the late 1990's because they supplied power to Hydro One customers beyond HCHI's borders. This particular project involves eliminating supply points from the 57M3 circuit from Jarvis TS. Sub-transmission charges will also be eliminated.

Business Value	Comments
Reliability/Performance	Changing the supply point to a HCHI controlled feeder will increase reliability because the circuit exposure outside of HCHI's territory will be eliminated. It also increases response time due to local presence of HCHI staff.
Community Relations	Customers in this supply area are fully aware of being supplied from a Hydro One feeder and that their LDC must wait for HO staff to arrive before a repair can be made or coordinated. The transfer of supply point will eliminate a HO response.
Safety	No coordination of emergency repairs would have to be made by HCHI which reduces the risk of an incident.
Regulatory Interference	No impact.
Environmental Stewardship	No impact.
Business Efficiency	A fairly detailed design has been completed.

Project Name – Lakeshore Road Rebuild – Phase 2

Prioritization Model:

		BEFORE			
	Project Name	**Lakeshore Road Re-Build (Phase 2)**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Significant	Most Likely	68	17.0
0.2	Community Relations	Severe	Very Likely	153	30.6
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship	Severe	Unlikely	51	5.1
	Sub Total of Weighted Score				57.7
		AFTER			
	Reliability/Performance	Small	Very Unlikely	1	0.3
	Community Relations	Significant	Likely	38	7.6
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					7.9
0.1	Business Efficiency	Small	Likely	5	0.5
	Delta of Weighted Score plus Business Efficiency				50.4
	Cost of Project				$ 300,000
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 300,000
	$/Weighted Score				5958

Discussion:

This is a continuation of a long range project started in 2009.

The Lake Erie shoreline is home to many single property cottages and clusters of cottages with privately owned roads or lanes. Traditionally this area was inhabited seasonally, but in recent years there is a trend for developing all season properties. This area runs along the lake for approximately 60 km. The age of the assets in these areas is 1950-60's vintage and much of it is installed in rear lots away from the travelled portion of the road. Due to its age the area is very well established with many encumbrances to our pole lines such as sheds, clothes lines, parked boats & cars, building materials, etc. This makes maintenance and restoration very inefficient and costly.

HCHI recognizes that these assets are approaching the end of life cycle and due to the length of line along the lake asset replacement will need to be a long term program likely exceeding twenty (20) years in time. The basic strategy encompasses the following concepts:

- Relocate primary and where possible secondary to roadways and laneways.
- Utilize underground assets where necessary
- Minimize the impact to the customer where new assets are installed where there was none before.

Business Value	Comments
Reliability/Performance	As the age of the assets increases the reliability will decrease with time. Access to rear lot always increases restoration times. Redeveloping will increase reliability and decrease restoration time.
Community Relations	There will be a trade-off with increased reliability and the location of assets. Relocating assets from the rear lot and placing them on roadways will likely be opposed by numerous property owners.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards) and relocating from the rear lot. The risk to HCHI staff will be improved due to better access, increased clearances of new designs, and elimination of deteriorated plant.
Regulatory Interference	No impact
Environmental Stewardship	The close proximity to the lake make transformer oil spills a sensitive issue. Eliminating old plant will decrease the risk.
Business Efficiency	The engineering design is in a preliminary state where the specific design details have yet to be decided upon.

Project Name – Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder

Prioritization Model:

		BEFORE			
	Project Name	**Conversion to Supply Innophos & Sherbrooke Area to 31M1 Feeder**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Moderate	Most Likely	25	6.3
0.2	Community Relations	Severe	Most Likely	184	36.8
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship	Severe	Unlikely	51	5.1
	Sub Total of Weighted Score				53.2
			AFTER		
	Reliability/Performance	Small	Unlikely	3	0.8
	Community Relations				0.0
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					0.8
0.1	Business Efficiency	Small	Likely	5	0.5
	Delta of Weighted Score plus Business Efficiency				52.9
	Cost of Project				$ 197,000
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 197,000
	$/Weighted Score				3724

Discussion:

Innophos is one of HCHI's largest customers. Their manufacturing processes require a reliable supply of electricity so that unscheduled restart costs can be avoided.

This project reduces sub-transmission charges by changing the supply point to an HCHI owned feeder.

In the past the Sherbrooke area has been the subject of low voltage issues. This project eliminates the long Dunnville F3 feeder.

Business Value	Comments
Reliability/Performance	The current supply to Innophos is from the 31M2 circuit which is HO owned. This circuit extends into the Wainfleet service territory of HO. This exposure beyond HCHI's border increases the frequency and duration of emergency work. This project increases reliability by decreasing the exposure. Low voltage issues in the Sherbrooke area will be rectified. The entire service area will have two points of supply instead of one (as it is now) increasing reliability.
Community Relations	Innophos is severely impacted financially by outages. The manufacturing processes within their plant cannot be restarted without clearing their machines of the old product. This takes time and effort from unscheduled resources.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards). The risk to HCHI staff will be improved due to increased clearances of new designs, and elimination of deteriorated plant.
Regulatory Interference	No impact.
Environmental Stewardship	The close proximity to the Grand River watershed and an old system of canals make a transformer oil spill a sensitive issue. Eliminating old plant will decrease the risk.
Business Efficiency	The engineering design is in a very preliminary state where the specific design details have yet to be decided upon.

Project Name – Alder Street – Dunnville – Conversion (Phase 1 – Civil Work)

Prioritization Model:

		BEFORE			
	Project Name	**Alder Street, Dunnville - Conversion (Phase 1 - Civil Works)**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Moderate	Most Likely	25	6.3
0.2	Community Relations	The Worst Case	Most Likely	500	100.0
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship	Moderate	Unlikely	7	0.7
	Sub Total of Weighted Score				112.0
		AFTER			
	Reliability/Performance	Small	Very Unlikely	1	0.3
	Community Relations	Significant	Unlikely	19	3.8
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					4.1
0.1	Business Efficiency	Small	Likely	5	0.5
	Delta of Weighted Score plus Business Efficiency				108.4
	Cost of Project				$ 300,000
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 300,000
	$/Weighted Score				2768

Discussion:

Alder Street in the community of Dunnville is receiving major deep service replacements in 2010 as part of the County's infrastructure replacement program. This street is supplied in part via rear lot assets and the assets on the road allowance are heavily encumbered by trees. Conversions of overhead assets to underground assets are very expensive partially due to the restoration work involved with roadways, sidewalks, and customers properties. When major deep service infrastructure improvements take place it is the opportune time to install civil electrical works which avoids the restoration costs.

Business Value	Comments
Reliability/Performance	Improvements due to removal of rear lot assets and the more reliable nature of underground distribution systems (at least from a weather perspective).
Community Relations	The destruction of perfectly good civil infrastructure to install underground assets is counterproductive from a County and customer perspective. Performing work before or during civil deep service work eliminates this concern.
Safety	Responding to issues with rear lot assets is always a safety concern due to limited access for tools and equipment. Responding to heavily treed overhead lines can produce some very dangerous situations for staff and the public. Conversion to underground reduces these concerns dramatically.
Regulatory Interference	No Impact
Environmental Stewardship	No Impact
Business Efficiency	The engineering design is in a very preliminary state where the specific design details have yet to be decided upon.

Project Name – Eliminate Feeds from Lythmore Distribution Station (Phase 1 – East)

Prioritization Model:

		BEFORE			
	Project Name	**Eliminate Feeds from Lythmore Distribution System (Phase 1 - East)**			
Weight	**Business Value**	**Consequence**	**Likelihood**	**Score**	**Weighted Score**
0.25	Reliability/Performance	Significant	Most Likely	68	17.0
0.2	Community Relations	Significant	Unlikely	19	3.8
0.25	Safety	Severe	Unlikely	51	12.8
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				33.6
		AFTER			
	Reliability/Performance				0.0
	Community Relations				0.0
	Safety				0.0
	Regulatory Interference				0.0
	Environmental Stewardship				0.0
					0.0
0.1	Business Efficiency	Significant	Likely	38	3.8
	Delta of Weighted Score plus Business Efficiency				37.4
	Cost of Project				$ 127,000
	Present Value of LV Savings				
	Cost of Project minus LV PV				$ 127,000
	$/Weighted Score				3400

Discussion:

This area is fed from HCHI owned circuits which are supplied from a HO distribution station. Eliminating the need for this station supply will eliminate sub-transmission charges.

Business Value	Comments
Reliability/Performance	In past years this area has been subject to low voltage when field regulators have been taken off line for maintenance or repair. Low voltage occurs at peak loading during the summer peaks of June, July, and August. Converting the area will eliminate the need to have regulators installed in the circuit and thus will correct the low voltage.
Community Relations	Will eliminate low voltage complaints.
Safety	Low voltage complaints always require intervention by HCHI field staff. Corrective actions usually involve changing transformer taps or reconfiguring the circuits temporarily to improve voltage. Eliminating the need to take corrective action will remove the risk of an incident.
Regulatory Interference	No Impact
Environmental Stewardship	No Impact
Business Efficiency	The engineering design is straightforward.

Appendix J – Five (5) Year Capital Forecast – 2009 - 2013

Haldimand County Hydro Inc.
Five Year Capital Forecast - 2009 - 2013
Cost Summary

	2009	2010	2011	2012	2013
Capital Construction Projects					
8Kv to 16Kv Conversion Projects					
Town Conversions					
Dunnville					
Central Lane - Phase II Conversion	$135,000.00				
Alder Street - Dunnville - Conversion		$300,000.00			
Main Street East					
Cedar to Queen Business Area					
Fairview - Pine to Tamarac					
Fairview - Pine to John					
Cedar & Broad - Padmount					
Maple Street					
Caledonia					
Orkney West of Sheffield				$110,000.00	
Kinross Street					
Cayuga					
Munsee Street North					
Hagersville					
Norcliff Retirement Home					
Rural Conversion					
Moulton Sherbrooke Townline Road - Rattlesnake Road Coversion, Dunnville	$148,000.00				
Hwy 6 N of 66 - Convert Using Stepdowns					
Haldimand Rd 66 to the East of Young Road					
Northshore Rd S of Canel Bank					
Darling Road S of Hwy 3					
Kohler Road - South from Existing Line to Irish Line					
Eliminate Distribution Substations					
Selkirk North DS	$295,000.00				
Jarvis DS			$496,000.00		
Dunnville DS					
Canfield DS					
Decewsville DS					
Selkirk South DS					
Projects to Eliminate LV Charges					
57M3 - Elimination for Concession 12, 13, 14, 15, 16, and 17		$160,000.00			
Lythmore DS - East - Phase I		$127,000.00			
57M3 - Elimination Concessions 9, 10, & 11			$160,000.00		
Lythmore DS - South - Phase II			$198,000.00		
Lythmore DS - North - Phase III				$135,000.00	
New Circuit to Selkirk South				$250,000.00	
Install Load Break Switches					
Install Load Break Switches 1			$25,000.00		
Install Load Break Switches 2				$25,000.00	
Install Load Break Switches 3					$25,000.00
Install Load Break Switches 4					
Install Load Break Switches 5					
27Kv Infrastructure - Major Line Construction					
Conversion of Line From Hagersville to Jarvis	$295,000.00				
Conversion to Supply Innophos to 31M1 (Alternate Supply)		$197,000.00			
Supply to Shelter Cove					
Reinsulate 31M2 - Bing to Water Plant or Alternate Path					
Townsend - Alternate Supply					
Haldimand Road 17 - Haldimand Rd 32 to Hwy 3					
John to Haldimand Rd #9					
McClung Road - River Crossing					
Hwy # 3 and Hwy # 56					

Haldimand County Hydro Inc.
Five Year Capital Forecast - 2009 - 2013
Cost Summary

	2009	2010	2011	2012	2013
Haldimand Rd 12 - Concession 7 to 5					
Haldimand Rd 20 - Haldimand Rd 9 to Concession 9					
Taylor Road N of Northshore Dr					
Replace Defective Infrastructure					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds - Melville Lane - Selkirk - Phase 1	$346,500.00				
Lakeshore Rebuilds - Phase 2		$300,000.00			
Lakeshore Rebuilds			$300,000.00		
Lakeshore Rebuilds				$300,000.00	
Lakeshore Rebuilds					$300,000.00
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Lakeshore Rebuilds					
Canal Bank				$110,000.00	
Miscellaneous Projects					
Recloser on 31M2					
27Kv North of Cayuga - Upgrade Wire Size					
Alternate Supply for Charles Cullen Parkway					
Pole Replacement Program					
Replace Defective Poles by Inspection Area	$492,520.00				
Replace Defective Poles by Inspection Area		$507,360.00			
Replace Defective Poles by Inspection Area			$522,581.00		
Replace Defective Poles by Inspection Area				$538,258.00	
Replace Defective Poles by Inspection Area					$554,406.00
Purchase Lines from Hydro One					
Hydro One Argyle Distribution Station F2 Feeder	$200,000.00				
Capital Project Allowance					
Capital Project Allowance 1					
Capital Project Allowance 2					
Capital Project Allowance 3			$69,293.00		
Capital Project Allowance 4				$448,589.00	
Capital Project Allowance 5					$1,929,999.00
Betterments					
Betterments 1	$257,365.00				
Betterments 2		$270,991.00			
Betterments 3			$314,074.00		
Betterments 4				$329,018.00	
Betterments 5					$343,962.00
Line Extensions					
Line Extensions	$506,411.00				
Line Extensions		$531,770.00			
Line Extensions			$566,345.00		
Line Extensions				$586,358.00	
Line Extensions 5					
Contributed Capital					
Contributed Capital	($47,800.00)				
Contributed Capital		($131,600.00)			
Contributed Capital			($115,068.00)		

Haldimand County Hydro Inc.
Five Year Capital Forecast - 2009 - 2013
Cost Summary

	2009	2010	2011	2012	2013
Contributed Capital				($115,068.00)	
Contributed Capital 5					($115,068.00)
Services Overhead					
Services Overhead	$86,931.00				
Services Overhead		$89,818.00			
Services Overhead			$83,418.00		
Services Overhead				$84,536.00	
Services Overhead 5					$85,655.00
Services Underground					
Services Underground	$88,333.00				
Services Underground		$98,844.00			
Services Underground			$66,415.00		
Services Underground				$53,660.00	
Services Underground 5					$40,905.00
Services (NEW) Miscellaneous					
Services (NEW) Miscellaneous	$6,749.00				
Services (NEW) Miscellaneous		$7,342.00			
Services (NEW) Miscellaneous			$6,485.00		
Services (NEW) Miscellaneous				$6,214.00	
Services (NEW) Miscellaneous 5					$5,943.00
Meters - Regular					
Meters - Regular	$29,199.00				
Meters - Regular		$87,763.00			
Meters - Regular			$41,295.00		
Meters - Regular				$31,048.00	
Meters - Regular 5					$20,801.00
Transportation Equipment					
Transportation Equipment	$350,039.00				
Transportation Equipment		$273,600.00			
Transportation Equipment			$315,586.00		
Transportation Equipment				$269,677.00	
Transportation Equipment					$37,150.00
Tools, Shop, and Measuring Equipment					
Tools, Shop, and Measuring Equipment	$53,864.00				
Tools, Shop, and Measuring Equipment		$39,333.00			
Tools, Shop, and Measuring Equipment			$50,108.00		
Tools, Shop, and Measuring Equipment				$50,692.00	
Tools, Shop, and Measuring Equipment					$51,276.00
Communications Equipment					
Communications Equipment					
Communications Equipment					
Communications Equipment					
Communications Equipment					
Communications Equipment					
Buildings and Fixtures					
Buildings and Fixtures	$19,435.00				
Buildings and Fixtures					
Buildings and Fixtures			$20,000.00		
Buildings and Fixtures				$20,000.00	
Buildings and Fixtures					$20,000.00
Office Equipment					
Office Equipment					
Office Equipment		$5,336.00			
Office Equipment			$5,000.00		
Office Equipment				$5,000.00	
Office Equipment					$5,000.00

Haldimand County Hydro Inc.
Five Year Capital Forecast - 2009 - 2013
Cost Summary

	2009	2010	2011	2012	2013
ESRI Distribution System Mapping					
ESRI Distribution System Mapping	$177,500.00				
ESRI Distribution System Mapping		$187,825.00			
ESRI Distribution System Mapping			$187,825.00		
ESRI Distribution System Mapping				$187,825.00	
ESRI Distribution System Mapping					$187,825.00
Computer Equipment - Hardware					
Computer Equipment - Hardware	$42,542.00				
Computer Equipment - Hardware		$18,676.00			
Computer Equipment - Hardware			$52,179.00		
Computer Equipment - Hardware				$36,518.00	
Computer Equipment - Hardware					$71,180.00
Computer Equipment - Software					
Computer Equipment - Software	$35,880.00				
Computer Equipment - Software		$241,243.00			
Computer Equipment - Software			$30,040.00		
Computer Equipment - Software				$32,000.00	
Computer Equipment - Software					$30,040.00
Smart Meters					
Smart Meters 1	$3,460,605.00				
Smart Meters 2		($96,041.00)			
Smart Meters 3					
Smart Meters 4					
Smart Meters 5					
Sentinal Light Rental Units					
Sentinal Light Rental Units 1	$3,977.00				
Sentinal Light Rental Units 2		$4,488.00			
Sentinal Light Rental Units 3			$5,424.00		
Sentinal Light Rental Units 4				$5,675.00	
Sentinal Light Rental Units 5					$5,926.00
Total	$6,983,050.00	$3,220,748.00	$3,400,000.00	$3,500,000.00	$3,600,000.00

Appendix K – Discretionary Capital Projects for 2011

Project Name – Eliminate Jarvis Distribution Station

Prioritization Model:

To be developed.

Discussion:

Jarvis DS located in the rural area of Walpole was installed in approximately 1973 and consists of a 5mVA station transformer and open steel structure. The project "Line to Supply Hagersville from Jarvis TS" completed in 2009 converted much of the load on this 27.6kV to 8.3kV station to 27.6kV. The remaining load at the station is anticipated to be in the range of 500kVA to 1500kVA. The 5mVA transformer can be utilized as a spare for other stations as there is currently no back-up transformer for Canfield DS, Dunnville DS, or Decewsville DS, or Selkirk South DS. This project would involve a combination of straight conversion to 27.6kV and the installation of step down transformers. This project supports HCHI's strategy to eliminate distribution stations.

Business Value	Comments
Reliability/Performance	Eliminating the station creates a spare 5mVA transformer needed for emergency replacement at other distribution stations. Having a spare transformer may reduce the length of an outage if a station transformer fails (while in service) in another location.
Community Relations	No Impact
Safety	Elimination of assets approaching the end of their lifecycle will increase safety for the public and HCHI staff.
Regulatory Interference	No impact.
Environmental Stewardship	A breach in the station transformer tanks could possibly lead to localized pollution as no containment system exists. Elimination prevents this from happening.
Business Efficiency	The engineering design is in a preliminary state where the specific design details have yet to be decided upon.

Project Name – Concessions 9, 10, and 11 – Eliminate 57M3 Supply Points

Prioritization Model:

To be developed.

Discussion:

Within the service territory of HCHI there are pole lines and circuits owned by Hydro One. These assets generally were retained by Hydro One after the sale of Hydro One assets to the LDC's in the late 1990's because they distributed power to Hydro One customers beyond HCHI's borders. This particular project involves eliminating supply points from the 57M3 circuit from Jarvis TS. Sub-transmission charges will also be eliminated.

Business Value	Comments
Reliability/Performance	Changing the supply point to a HCHI controlled feeder will increase reliability because the circuit exposure outside of HCHI's territory will be eliminated. It also increases response time due to local presence of HCHI staff.
Community Relations	Customers in this supply area are fully aware of being supplied from a Hydro One feeder and that their LDC must wait for HO staff to arrive before a repair can be made or coordinated. The transfer of supply point will eliminate a HO response.
Safety	No coordination of emergency repairs would have to be made by HCHI which reduces the risk of an incident.
Regulatory	No impact.
Interference	
Environmental Stewardship	No impact.
Business Efficiency	A preliminary design has been completed.

Project Name – Eliminate Feeds from Lythmore Distribution Station (Phase 2 – South)

Prioritization Model:

To be developed.

Discussion:

This area is fed from HCHI owned circuits which are supplied from a HO distribution station. Eliminating the need for this station supply will eliminate sub-transmission charges.

Business Value	Comments
Reliability/Performance	In past years this area has been subject to low voltage when field regulators have been taken off line for maintenance or repair. Low voltage occurs at peak loading during the summer peaks of June, July, and August. Converting the area will eliminate the need to have regulators installed in the circuit and thus will correct the low voltage.
Community Relations	Will eliminate low voltage complaints.
Safety	Low voltage complaints always require intervention by HCHI field staff. Corrective actions usually involve changing transformer taps or reconfiguring the circuits temporarily to improve voltage. Eliminating the need to take corrective action will remove the risk of an incident.
Regulatory Interference	No Impact
Environmental Stewardship	No Impact
Business Efficiency	The engineering design is in a conceptual stage only where the specific design details have yet to be decided upon.

Project Name – Lakeshore Road Rebuild – Phase 3

Prioritization Model:

To be developed.

Discussion:

This is a continuation of a long range project started in 2009.

The Lake Erie shoreline is home to many single property cottages and clusters of cottages with privately owned roads or lanes. Traditionally this area was inhabited seasonally, but in recent years there is a trend for developing all season properties. This area runs along the lake for approximately 60 km. The age of the assets in these areas is 1950-60's vintage and much of it is installed in rear lots away from the travelled portion of the road. Due to its age the area is very well established with many encumbrances to our pole lines such as sheds, clothes lines, parked boats & cars, building materials, etc. This makes maintenance and restoration very inefficient and costly.

HCHI recognizes that these assets are approaching the end of life cycle and due to the length of line along the lake asset replacement will need to be a long term program likely exceeding twenty (20) years in time. The basic strategy encompasses the following concepts:

- Relocate primary and where possible secondary to roadways and laneways.
- Utilize underground assets where necessary.
- Minimize the impact to the customer where new assets are installed where there was none before.

Business Value	Comments
Reliability/Performance	As the age of the assets increases the reliability will decrease with time. Access to rear lot always increases restoration times. Redeveloping will increase reliability and decrease restoration time.
Community Relations	There will be a trade-off with increased reliability and the location of assets. Relocating assets from the rear lot and placing them on roadways will likely be opposed by numerous property owners.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards) and relocating from the rear lot. The risk to HCHI staff will be improved due to better access, increased clearances of new designs, and elimination of deteriorated plant.
Regulatory Interference	No impact
Environmental Stewardship	The close proximity to the lake makes a transformer oil spill a sensitive issue. Eliminating old plant will decrease the risk.
Business Efficiency	The engineering design is in a conceptual stage only where the specific design details have yet to be decided upon.

Appendix L – Discretionary Capital Projects for 2012

Project Name – Orkney West of Shetland Conversion - Caledonia

Prioritization Model:

To be developed.

Discussion:

This area can be characterized by older type construction with substandard clearances (as compared to today's standards) and it is being supplied by HO's Argyle DS. Sub-transmission charges will be reduced.

Business Value	Comments
Reliability/Performance	As the age of the assets increases the reliability will decrease with time. Redeveloping will increase reliability and decrease restoration time.
Community Relations	No Impact.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards). The risk to HCHI staff will be improved due to increased clearances of new designs, and elimination of deteriorated plant.
Regulatory Interference	No impact
Environmental Stewardship	No impact.
Business Efficiency	The engineering design is in a conceptual stage only where the specific design details have yet to be decided upon.

Project Name – Eliminate Feeds from Lythmore Distribution Station (Phase 3 – North)

Prioritization Model:

To be developed.

Discussion:

This area is fed from HCHI owned circuits which are supplied from a HO distribution station. Eliminating the need for this station supply will eliminate sub-transmission charges.

Business Value	Comments
Reliability/Performance	In past years this area has been subject to low voltage when field regulators have been taken off line for maintenance or repair. Low voltage occurs at peak loading during the summer peaks of June, July, and August. Converting the area will eliminate the need to have regulators installed in the circuit and thus will correct the low voltage.
Community Relations	Will eliminate low voltage complaints.
Safety	Low voltage complaints always require intervention by HCHI field staff. Corrective actions usually involve changing transformer taps or reconfiguring the circuits temporarily to improve voltage. Eliminating the need to take corrective action will remove the risk of an incident.
Regulatory Interference	No Impact
Environmental Stewardship	No Impact
Business Efficiency	The engineering design is in a conceptual stage only where the specific design details have yet to be decided upon.

Project Name – New Circuit to Selkirk South DS

Discussion:

This project is no longer required because the new supply was accomplished in 2009 under project titled "**Eliminate Selkirk North DS**".

Project Name – Lakeshore Road Rebuild – Phase 4

Prioritization Model:

To be developed.

Discussion:

This is a continuation of a long range project started in 2009.

The Lake Erie shoreline is home to many single property cottages and clusters of cottages with privately owned roads or lanes. Traditionally this area was inhabited seasonally, but in recent years there is a trend for developing all season properties. This area runs along the lake for approximately 60 km. The age of the assets in these areas is 1950-60's vintage and much of it is installed in rear lots away from the travelled portion of the road. Due to its age the area is very well established with many encumbrances to our pole lines such as sheds, clothes lines, parked boats & cars, building materials, etc. This makes maintenance and restoration very inefficient and costly.

HCHI recognizes that these assets are approaching the end of life cycle and due to the length of line along the lake asset replacement will need to be a long term program likely exceeding twenty (20) years in time. The basic strategy encompasses the following concepts:

- Relocate primary and where possible secondary to roadways and laneways.
- Utilize underground assets where necessary.
- Minimize the impact to the customer where new assets are installed where there was none before.

Business Value	Comments
Reliability/Performance	As the age of the assets increases the reliability will decrease with time. Access to rear lot always increases restoration times. Redeveloping will increase reliability and restoration time.
Community Relations	There will be a trade-off with increased reliability and the location of assets. Relocating assets from the rear lot and placing them on roadways will likely be opposed by numerous property owners.
Safety	The risk of public safety will be improved by eliminating old assets (decreased clearances as compared with new standards) and relocating from the rear lot. The risk to HCHI staff will be improved due to better access, increased clearances of new designs, and elimination of deteriorated plant.
Regulatory Interference	No impact
Environmental Stewardship	The close proximity to the lake make transformer oil spills a sensitive issue. Eliminating old plant will decrease the risk.
Business Efficiency	The engineering design is in a conceptual stage only where the specific design details have yet to be decided upon.

Project Name – Canal Bank - Moulton

Prioritization Model:

To be developed.

Discussion

This project is a continuation of the project **"**Conversion to Supply Innophos and Sherbrooke Area to 31M1 Feeder" which is scheduled for completion in 2010. It involves converting an existing 8.3kV line to 27.6kV along Canal Bank Road. The poles in this line are owned by Hydro One and HCHI only owns the circuit. Conversion involves changing cross arm construction and installing new insulators. The conversion of the laterals off this main line will be by accomplished using step down transformers or straight conversion. This project supports HCHI's strategy to convert 8.3kV to 27.6kV.

Business Value	Comments
Reliability/Performance	The existing circuit is nearing end of life (cross arm construction). Replacement of arms and insulators will increase reliability.
Community Relations	No Impact.
Safety	Maintaining equipment at end of life is more risky than maintaining new equipment. This is particularly relevant in this case because this circuit is off road and access is difficult. This reduces the risk of an incident.
Regulatory Interference	No Impact.
Environmental Stewardship	No Impact.
Business Efficiency	The engineering design is in a conceptual stage only where the specific design details have yet to be decided upon.

Appendix M - Discretionary Capital Projects Prioritization Model – Kinectrics Inc. Report No. – K-014704-RA-0002-R02

"DISCRETIONARY" CAPITAL PROJECTS PRIORITIZATION MODEL FOR Haldimand County Hydro Inc.

Kinectrics Inc. Report No.: K-014704-RA-0002-R02

Confidential & Proprietary Information
Contents of this report shall not be disclosed
Without authority of client.
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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Haldimand County Hydro Inc.

@Kinectrics Inc., 2009.

"DISCRETIONARY" CAPITAL PROJECTS PRIORITIZATION
FOR
Haldimand County Hydro Inc.

Kinectrics Inc. Report No.: K-014704-RA-0002-R02

March 12, 2009

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REVISION HISTORY

Revision Number	Date	Comments	Approved
R00	January 22, 2009	Original Draft	
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1 INTRODUCTION

Haldimand County Hydro Inc. (HCHI) retained the services of Kinectrics Inc. (Kinectrics) to perform the following tasks:

1. Carry out Asset Condition Assessment (ACA) of the HCHI's distribution assets divided into 10 Asset Groups.
2. Carry out Risk Assessment for the Asset Groups with Sufficient Amount of Information.
3. Provide recommendations on prioritized data gaps closure.
4. Recommend Capital Replacements Plan (CRP) for the next 20 years
5. Review HCHI's maintenance practices.
6. Develop the methodology for prioritizing "discretionary" capital projects.

This report summarizes task 6. The results for tasks 1 through 5 are presented in a separate report: "DISTRIBUTION ASSET CONDITION ASSESSMENT", Report Number K-014704-RA-0001

In addition to capital replacements triggered by the Asset Condition Assessment findings, some capital expenditures arise from expansion of the existing distribution system. Such expenditures typically fall under one of two categories:

1. "Demand" Expenditures required for addressing specific problem, such as new generation, load connections or known load growth in the area that will result in overloading of some of the existing facilities.
2. "Discretionary" Expenditures that alleviate certain potential risks associated with the utility's corporate values and objectives, such as reliability of supply, environmental concerns, financial considerations and safety.

As a part of the project scope Kinectrics developed, in conjunction with HCHI senior staff, a risk based methodology for prioritizing "discretionary" capital projects based on their cost and impact on mitigating risks associated with HCHI's Business Values and Objectives.

This methodology reflects industry standard in prioritizing projects that provide benefits across several Business Values and, as such, is being used by many large utilities, specifically Hydro One, Barry Hydro (now part of PowerStream) and Toronto Hydro in Ontario. The methodology was subsequently tested by applying it to several of HCHI's actual projects.

2 METHODOLOGY FOR PRIORITIZING "DISCRETIONARY" CAPITAL PROJECTS

2.1 Business Values (sometimes also referred to as Business Criteria)

Most utilities have a Mission Statement and strategic goals that, at a high level, describe corporate aspirations, goals and objectives. Business Values (BVs) are designed to facilitate achievement of the strategic goals by designing an investment portfolio in a manner that cost-effectively manages the overall risk to these strategic goals.

Typical BVs are:

- Reliability Performance
- Financial Targets
- Customer Satisfaction
- Reputation/Brand Name Maintenance (Public Relations)
- Safety Performance (employees and public)
- Environmental Requirements
- Regulatory Relationship
- Market Efficiency

The first step in the methodology described here is to establish a set of BVs that accurately reflect strategic goals of a particular company and are endorsed by the Senior Management and preferably by the Board of Directors.

2.2 Business Values Attributes and Key Performance Indicators

Business Values Attributes (BVAs) provide a means of assessing BVs and are specific to each company. For example, BVAs for Reliability BV could be SAIFI, SAIDI, unsupplied energy in system min (total unsupplied energy divided by the system peak and multiplied by 60) , etc., BVAs for Financial BV could be Credit Rating and Net Income, BVA for Safety could be Employees Time off Work due to Injuries, etc.

Criteria for measuring risk consequences to BVAs are sometimes referred to as Key Performance Indicators (KPIs). Typically, for each attribute there are 5 levels of KPIs: The Worst Case, Severe, Major, Moderate and Minor. KPIs allow a quantitative assessment of BVAs. Again, these KPIs are company specific and usually are updated annually. KPIs depend on factors such as company size, tolerance to various risks, corporate priorities, etc.

Table 2-2 (shown below for illustrative purposes only) contains an example of BVs and corresponding BVAs and KPIs.

Table 2-2 Example of BVs, BVAs and KPIs

BV	Attribute	Worst Case	Severe	Major	Moderate	Minor
Financial	1) Net Income --- 2) Credit Rating	1) >$50M Less --- 2) Default	1)$25-50 Less --- 2) Below Investment Grade	$10-25M Less --- 2) Credit downgrade	1) $1-10M Less --- 2) Credit "watch"	1)<1M Less --- 2) Some concern
Reliability	1) SAIFI --- 2) SAIDI	1) >25% increase --- 2) >20% increase	1) 15-25% increase --- 2) 10-20% increase	1) 5-15% increase --- 2) 5-10% increase	1) 0-5% increase --- 2) 1-5% increase	1)No decrease --- 2)No decrease
Safety	Employees Safety	Fatality	Permanent Injury	Serious Injury	Increase in minor injuries	No change
Business Efficiency	Employees Retention	Departure of all key staff: business can not be sustained	Departure of some key staff: some critical projects will not be completed	Insufficient # of skilled staff: some critical projects will be late	Shortage of resources: some projects will not be completed	Shortage of trained resources: some projects will be late

2.3 Risk Matrix

Risk to BVs depends on two factors: Consequence of a risk to BV and Likelihood of a risk to BV. The former is described above using BVAs and KPIs. The latter could be divided into 5 categories as follows:

1. Very Likely
2. Likely
3. Medium
4. Unlikely
5. Remote

For each risk occurrence, a decision on selecting the appropriate risk Likelihood Level is based upon a combination of factors, namely expected annual frequency, expected annual probability, and probability over a planning period, typically 5 years. Rather than a hard number, these are usually a range of values, e.g. 1 in 5 to 1 in 50 years for frequency, 0.2 to 0.35 for probability, and 50% to 65% for probability over a planning period. Again, the ranges are company specific and reflect past history, recent changes/modifications, and staff experience.

A Risk Matrix combines Consequences of risk and Likelihood of risk to estimate risk to BVs as shown in Table 2-3 below.

Table 2-3 Typical Risk Matrix

CONSEQUENCE

LIKELIHOOD	Minor	Moderate	Major	Severe	Worst Case
Very Likely					
Likely					
Medium					
Unlikely					
Remote					

The risk value in each cell could be pre-determined using the following steps:

1. Establish consequences using logarithmic scale as they usually increase exponentially rather than laniary
2. Multiplying Consequences of risk by Likelihood of risk
3. Normalize the values between "Remote Minor" and "Very Likely Worst Case" cells so that each cell value is an integer: this makes it easier to compare and rate the risks while still having a variety of unique integer numbers in the lower risk range and, at the same time, allows for highlighting unacceptable risks, say with the scores above 200.

Having all the cells populated with the appropriate values allows staff to determine the Risk Score (RS) by simply picking an appropriate Risk Matrix cell based on the estimated levels of Likelihood and Consequence of risk associated with a certain project. This is done for EACH BV.

The purpose of investments in general and, in this case, "discretional" projects in particular, is to alleviate the overall risk to BVs in the most cost-effective manner. After a "discretional" capital investment is made, the overall risk across the BVs will be lowered (although a project typically does not affect all the BVs).

It is worth noting that some degree of subjectivity will always be present in populating the Risk Matrix. Therefore, it is important to have designated “experts” within the organization who can ensure consistency in estimating mitigated risk with each project being evaluated.

2.4 Prioritization Methodology

The effectiveness of each of the projects is assessed by calculating the associated Cost to Risk Reduction Factor (CRRF). To do that, the overall risk is first calculated before the project is implemented (existing situation) and then assuming the project is completed. The resultant overall risk reduction is then compared with the project cost using the following formula:

$CRRF = Project\ Cost / \Sigma(\Delta R_i \times WBV_i)$ where

ΔR_i is risk reduction to BV_i if a project were to be completed

WBV_i is Weight assigned to BV_i (based on the corporate priorities)

The projects are then prioritized by their CRRFs, from the lowest to the highest, i.e. the lower cost of per unit of risk reduction the more cost effective the project is.

2.5 Summary

The methodology to prioritize "discretional" projects involves the following steps:

1. Review Business Values (BVs) that reflect corporate strategic goals.
2. Establish Business Values Attributes (BVAs) and Key Performance Indicators (KPIs) as the risk consequence measures for each of the BVs.
3. Put together and populate with normalized values the Risk Matrix that combines Likelihood of risk and Consequences of mitigated risk to BVs due to a certain project.
4. Estimate the overall risk to BVs first assuming the existing conditions and then assuming the project has been completed.
5. Calculate Cost to Risk Reduction Cost Ratio (CRRF) for each proposed "discretional" capital project.
6. Prioritize incremental investments above the minimum level based on the calculated CRRF, from the lowest to the highest.

3 HCHI-SPECIFIC MATRICES FOR PRIORITIZING "DISCRETIONARY" CAPITAL PROJECTS

3.1 Likelihood and Consequence Risk Matrix

Table 3-1 shows a generic Likelihood vs. Risk Consequence Matrix. A value in each is cell is calculated as e^x (with x=1, 2, 3, 4 or 5, depending on the perceived risk consequence) multiplied by the likelihood (0.1 for very unlikely, 0.25 for unlikely, etc.) and than normalized so that the least likely lowest risk score is =1.

Table 3-1 Likelihood and Consequence Risk Matrix

LIKELIHOOD/CONSEQUENCE	SMALL	MODERATE	SIGNIFICANT	SEVERE	THE WORST CASE
Most Likely (>90%)	9	25	68	184	500
Very Likely (>75%)	8	21	56	153	417
Likely (50/50)	5	14	38	102	278
Unlikely (<25%)	3	7	19	51	139
Very Unlikely (<10%)	1	3	7	20	56

3.2 Business Values and Associated Consequences

The methodology described in the previous section was customized with the significant input from HCHI's senior staff to properly reflect HCHI's BVs, associated Weights and BVAs, and perceived project-specific alleviated risks. Table 3-2 shows the resultant matrix.

Appendix I shows an example of applying this methodology using a spread sheet tool developed by HCHI for comparing two HCHI capital projects: Table AI-1 summarizes results for "Central Lane Phase II Conversion – Dunville" (Project 1) and Table AI-2 for "Construction of Line Hagersville to Jarvis" (Project 2).

The resultant CRRF for Project 1 is 3896 and for Project 2 9353 meaning that Project 1 is considerably more cost-effective in mitigating the overall Corporate Risks than Project 2. Therefore, if it is not possible to fund both projects, HCHI should proceed with Project 1 first.

Table AI-2 also illustrates how projected financial savings ($71K in this case) are accounted for by directly subtracting them the project cost and thus reducing CRRF (in our example, even after considering specific financial savings due to Project 2, Project 1 still remained more favorable). It is worth noting, however, that if the projected financial savings exceed the project cost, there is no need to use this methodology as the project would beneficial based on its financial merit alone and, thus, should be implemented as soon as possible.

Table 3-2 HCHI-Specific BVs, BVAs and Risk Consequences Matrix

Project Specific Risk Consequences

Business Value (BV)	Weight	Business Value Attribute (BVA)	The Worst Case (All BVs except BE) (Highest Avoided Risk for BE)	Severe (All BVs Except BE) (Most Risk to BE Avoided)	Significant (All BVs except BE) (Medium Risk to BE)	Moderate (All BVs Except BE) (Significant Risk to BE)	Small (All BVs Except BE) (Highest Risk to BE)
1. Business Efficiency (BE)[Note 2]	10%	- Status of Detail Project Design	Exact Cost is Known, e.g. Purchase of Assets from Another Utility	Detailed best possible design done,actual cost expected to be within ±10% of estimate	Fairly detailed design done, actual cost is expected to be within ±25% of estimate	Some detailed design done, actual cost expected to be within ±50% of the estimate	Very preliminary design done, actual cost may be 50-100% higher than estimate
2. Reliability Performance	25%	- Impact on SAIDI and SAIFI	Significant future increaseof local contribution to SAIFI and/or SAIDI resulting in Regulatory non-compliance	Significan future increase of local contribution to SAIFI and/or SAIDI	Small future increase of local contribution to SAIFI and/or SAIDI	No future change from existing local contribution to SAIFI and/or SAIDI	Small future reduction of local contribution to SAIFI/SAIDI
		- Impact on Voltage		Voltage outside of the CSA "extreme" range	Voltage outside of the CSA "normal" range but within the CSA "extreme" range		
3. Community Relations	20%	- Community Impact	Big negative Impact on Community, i.e. dealy of road construction work, if project is not done	Some negative impact on Community, e.g. known poublic concern with existing system condition	Negative impact mitigated and several customers oppose the project	Negative impact mitigated and very few customers still oppose the porject	
4. Safety	25%	- Eliminating Preventable Public Accidents	More than one accident involving member of the public	A single accident involving member of the public			
		- Eliminating Preventable Work Place Accidents	More than one accident involving HCHI staff	A single accident involving HCHI staff			
		- Managing Property Damage Claims	Future local property claims increase by more than 100% over 3-year rolling average	Future local property claims increase by 50% to 100% over 3-year rolling average	Future local property claims increase by 25% to 50% over 3-year rolling average	Future local property claims increase by 10% to 25% over 3-year rolling average	Future local property claims increase by less than 10% over 3-year rolling average
5. Regulatory Interface	10%	- Regulatory Compliance	Complete loss of credibility and Regulatory compliance is closely monitored by the Regulatory Authority(s)	Penalities are imposed by a Regulatory Authority(s)	Non-compliance results in Regulatory Authority(s) complaint to the President and/or the Board of Directors	Non-compliance resolved with the President's involvement	Non-compliance resolved by the technical staff
6. Environmental Stewardship	10%	- Environmental Spills	Major spill in a sensitive area	Minor spill in a sensitive area	Major spill outside of a sensitive area	Minor spill outside of a sensitive area	

Note 1. The Risk Consequences and their likelyhood need to be assessed for the existing condition and then assuming the project were completed. The weighted sum of the differentces for all the BVs is the Risk Score Change (RSC).

Note 2. For Business Efficiency, not doing the project has NO risk of overspending. The better quality of an estimate, the more of "overspending" risk is eliminated, i.e. the best estimate eliminates the highst risk.The score for the avoided risk should be added to the calculated Delta (BEFORE-AFTER)

Note 3. For some of the BVAs fewer than 5 Risk Consequence categories are applicable

It is worth noting the following:

- To assess the risk alleviated by each project, the combined weighted Risk Score needs to first be established for the existing conditions and then re-evaluated assuming the project has been completed. The difference is the CRRF.
- Since there is NO risk of overspending associated with not doing the project (existing condition), the better the quality of the estimate, the less the financial risk of overspending. In other words, the best quality estimate eliminates the highest risk of overspending and, thus, lowers the ratio of Cost to Risk ($/Δ Risk). To account for that the Business Efficiency (BE) Risk Mitigation Score (always derived assuming "Likely" from the Table 3-1), is added to the CRRF due to the other BVs. This results in better quality estimates contributing more to the overall risk mitigation.
- For some of the BVAs not all the Risk Consequences are applicable to a given project.
- If a project results in specific projected savings, e.g. elimination of LV charges following a voltage conversion, the estimated Present Value over a pre-defined period of time should be subtracted from the project's cost (if the savings exceed the project cost, it means there is a solid business case for the project to go forward without any further assessment of its impact on BVs)

APPENDIX I APPLICATION OF PRIORITIZATION METHODOLOGY: EXAMPLES

Table AI-1 Project 1: Central Lane Phase II Conversion – Dunville

		BEFORE			
	Project Name	Central Lane Phase II Conversion - Dunnville			
Weight	Business Value	Consequence	Likelihood	Score	Weighted Score
0.25	Reliability/Performance	Significant	Likely	38	9.5
0.2	Community Relations	Severe	Unlikely	51	10.2
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				**24.7**
		AFTER			
0.25	Reliability/Performance	Small	Very Unlikely	1	0.3
0.2	Community Relations				0.0
0.25	Safety				0.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				**0.3**
0.1	Business Efficiency	Severe	Likely	102	10.2

Delta of Weighted Score plus Business Efficiency	34.7
Cost of Project	$ 135,000
Present Value of LV Savings	$ -
Cost of Project minus LV PV	$ 135,000
$/ Weighted Score	**3896**

Table AI-2 Project 2: Construction of Line Hagersville to Jarvis

		BEFORE			
	Project Name	Const. of Line Hagersville to Jarvis			
Weight	Business Value	Consequence	Likelihood	Score	Weighted Score
0.25	Reliability/Performance	Moderate	Most Likely	25	6.3
0.2	Community Relations				0.0
0.25	Safety	Severe	Very Unlikely	20	5.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship	Moderate	Most Likely	25	2.5
	Sub Total of Weighted Score				**13.8**
		AFTER			
0.25	Reliability/Performance				0.0
0.2	Community Relations				0.0
0.25	Safety				0.0
0.1	Regulatory Interference				0.0
0.1	Environmental Stewardship				0.0
	Sub Total of Weighted Score				**0.0**
0.1	Business Efficiency	Severe	Likely	102	10.2

Delta of Weighted Score plus Business Efficiency	24.0
Cost of Project	$ 295,000
Present Value of LV Savings	$ 71,000
Cost of Project minus LV PV	$ 224,000
$/ Weighted Score	**9352.8**

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1			**Overview**
		1		Overview of Operating Revenue
		2		Summary of Operating Revenue Table
	2			**Distribution Revenue**
		1		Distribution Revenue and Variance Analysis
			A	Embedded Distributor – Norfolk Power Distribution Inc. Supporting Letters – Supply Situation
		2		Weather Normalized Load and Customer/ Connection Forecast
			B	Monthly Data Used for Regression Analysis
			C	Monthly Heating & Cooling Degree Data Used in Analysis of Load Forecast Models
	3			**Other Operating Revenue**
		1		Summary of Other Operating Revenue
		2		Variance Analysis on Other Operating Revenue

OVERVIEW OF OPERATING REVENUE

Details of Haldimand County Hydro Inc's ("HCHI") operating revenue for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, the 2009 Bridge Year and the 2010 Test Year are presented in this Exhibit. This Exhibit also provides a variance analysis by rate class of the material changes in operating distribution revenue components. Distribution revenue does not include revenue from commodity sales or other cost of power pass through costs.

HCHI's distribution revenues have been calculated using the appropriate OEB-approved Tariff of Rates and Charges for the applicable year. Total distribution revenue includes OEB-approved specific service charges, rent from electric property, late payment charges, interest and other miscellaneous revenues. Note that interest does not include any amount for OEB Deferred Interest calculated on account of deferral and variance accounts.

A summary of operating revenues is presented in Table 1 of this exhibit at Tab 1, Schedule 2. Year over year variances are shown in Table 2 at Tab 2, Schedule 1, with the amounts exceeding the materiality threshold of $53,080 having been highlighted in the table. The variance analysis with individual explanations in distribution revenue follow this table and the variance analysis of other distribution revenue appear in Tab 3, Schedule 2.

Distribution Revenue

Information related to HCHI's distribution revenue includes details such as weather normalized forecasting methodology, normalized volume and customer counts. Variance analysis on the distribution revenue is set out in Tables 3 through Table 8 at Tab 2, Schedule 1.

Other Revenue

Other revenues include such things as late payment charges, specific service charges, Standard Supply Service Administrative charge, rent from electric property, retail service revenues, miscellaneous service revenues and interest. A summary of these operating revenues is presented in Tables 27 and 28, at Tab 3, Schedule 1 with a materiality analysis of variances presented in Tab 3, Schedule 2.

SUMMARY OF OPERATING REVENUE

The following Table 1 summarizes HCHI's total base distribution revenue requirement calculated on HCHI's weather normalized forecasts, other distribution revenue and total service revenue requirement. The revenue numbers for each of the Actual years are from HCHI's audited Financial Statements which reconcile to the annual filings with the OEB. The 2009 Bridge year distribution revenue is based on HCHI's OEB-approved rates applied to HCHI's 2009 forecast for customer counts and normalized usage. The proposed 2010 Test year distribution revenue is calculated on HCHI's proposed 2010 distribution rates applied to the 2010 forecast of customer counts and normalized usage.

Table 1
Summary of Operating Revenue ($)

Description	2006 Board Approved	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year "Proposed"
Distribution Revenues:						
Residential	7,792,703	6,990,409	7,777,545	7,666,133	7,563,830	8,692,594
General Service < 50 kW	1,735,505	1,584,125	1,803,516	1,813,034	1,810,356	2,112,502
General Service 50 to 4999 kW	1,951,941	1,825,421	1,949,287	1,853,988	1,714,135	1,548,436
Street Lighting	74,541	67,194	75,870	77,424	77,181	199,036
Sentinel Lights	21,198	18,783	20,272	19,860	18,141	74,483
Unmetered Scattered Load	20,583	13,779	20,256	19,389	20,004	22,822
Embedded Distributor - HONI	-	-	-	-	-	173,771
Base Distribution Revenue	11,596,471	10,499,711	11,646,747	11,449,828	11,203,647	12,823,644
Plus Low Voltage Charges	315,726	-	-	-	-	-
Total Base Distribution Revenue Requirement	11,912,197	10,499,711	11,646,747	11,449,828	11,203,647	12,823,644
Other Distribution Revenue:						
Late Payment Charges	153,625	288,988	282,191	292,443	319,125	319,125
Specific Service Charges	379,469	167,625	215,325	200,939	240,397	212,558
Other Distribution Revenue	235,228	862,859	892,382	784,312	641,324	583,651
Total Other Revenue	768,322	1,319,472	1,389,898	1,277,694	1,200,846	1,115,334
Total Service Revenue Requirement Net of Transformer Allowance	12,680,519	11,819,184	13,036,645	12,727,522	12,404,493	13,938,978

Notes - Table1 Information

1. The Standard Supply Service ("SSS") Administrative Charge revenue has been included in Other Distribution Revenue as it represents a revenue offset.

2. The revenue for the G/S 50 to 4999 kW rate class is net of transformer allowance credits applicable to eligible customers in this rate class.

3. The Low Voltage Charges billed are not included in the Actual Years, Bridge Year, and Test Year; as per the OEB's letter dated June 13, 2006 with guidance to account for these billed amounts in account '4075" – a cost of power pass through account, as compared to the accounting in the 2006 Board Approved as per the guidelines in preparation of the 2006 EDR Application.

4. Embedded Distributor Rate Class notation:
    a. Revenue for the 2010 Test year represents the "new" embedded situation with Hydro One Networks Inc. ("HONI") as described in Exhibit 1, Tab 1 Schedule 12, with rate details in Exhibit 8, Tab 1, Schedule 1. Cost allocation was used to determine the revenue requirement from this "new proposed" rate class. See Exhibit 7, Tab 1, Schedule 3 for details.

DISTRIBUTION REVENUE AND VARIANCE ANALYSIS

HCHI's distribution revenue and variance for 2006, 2007, 2008, and 2009 have been calculated using HCHI's OEB-approved Distribution Rates for 2006, 2007, 2008, and 2009. The 2010 distribution revenue has been calculated using the proposed rates in this Cost of Service Rate Application as detailed in Exhibit 8. Distribution revenue does not include commodity-related revenue.

HCHI has provided a variance on distribution revenues for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge year, and 2010 Test year in Table 2 below. The variances exceeding HCHI's materiality threshold of $53,080 have been highlighted. As discussed in previous Exhibits, the materiality threshold was calculated as set out in the OEB's *Chapter 2 Filing Requirements for Transmission and Distribution Applications*, updated May 27, 2009 (the "Filing Requirements"), in particular that:

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

A variance analysis from year to year follows the Table 2.

Table 2
Distribution Revenue with Variances

Description	2006 Board Approved	2006 Actual Year	Variance from Board Approved	2007 Actual Year	Variance from 2006 Actual	2008 Actual Year	Variance from 2007 Actual	2009 Bridge Year "Normalized"	Variance from 2008 Actual	2010 Test Year "Normalized"	Variance from 2009 Bridge
Distribution Revenues:											
Residential	7,792,703	6,990,409	(802,294)	7,777,545	787,136	7,666,133	(111,412)	7,563,830	(102,303)	8,692,594	1,128,764
General Service < 50 kW	1,735,505	1,584,125	(151,380)	1,803,516	219,391	1,813,034	9,517	1,810,356	(2,678)	2,112,502	302,146
General Service 50 to 4999 kW	1,951,941	1,825,421	(126,520)	1,949,287	123,867	1,853,988	(95,299)	1,714,135	(139,853)	1,548,436	(165,699)
Street Lighting	74,541	67,194	(7,347)	75,870	8,676	77,424	1,554	77,181	(243)	199,036	121,855
Sentinel Lights	21,198	18,783	(2,415)	20,272	1,489	19,860	(412)	18,141	(1,719)	74,483	56,342
Unmetered Scattered Load	20,583	13,779	(6,804)	20,256	6,477	19,389	(867)	20,004	615	22,822	2,818
Embedded Distributor - HONI			-		-		-		-	173,771	173,771
Base Distribution Revenue	11,596,471	10,499,711	(1,096,760)	11,646,747	1,147,035	11,449,828	(196,918)	11,203,647	(246,181)	12,823,644	1,619,997
Plus Low Voltage Charges	315,726	-	(315,726)	-	-	-	-	-	-	-	-
Total Base Distribution Revenue Requirement	11,912,197	10,499,711	(1,412,486)	11,646,747	1,147,035	11,449,828	(196,918)	11,203,647	(246,181)	12,823,644	1,619,997
Other Distribution Revenue:											
Late Payment Charges	153,625	288,988	135,363	282,191	(6,797)	292,443	10,252	319,125	26,682	319,125	-
Specific Service Charges	379,469	167,625	(211,844)	215,325	47,700	200,939	(14,386)	240,397	39,458	212,558	(27,839)
Other Distribution Revenue	235,228	862,859	627,631	892,382	29,523	784,312	(108,070)	641,324	(142,988)	583,651	(57,673)
Total Other Revenue	768,322	1,319,472	551,150	1,389,898	70,426	1,277,694	(112,204)	1,200,846	(76,848)	1,115,334	(85,512)
Total Service Revenue Requirement Net of Transformer Allowance	12,680,519	11,819,184	(861,335)	13,036,645	1,217,461	12,727,522	(309,123)	12,404,493	(323,029)	13,938,978	1,534,485

Distribution Revenue Variance Analysis

The variance analysis is detailed by customer class with the majority of the variance explained in two components – a volume variance and a price variance.

The volume variance is calculated as the difference in usage and in the customer counts year over year, times the variable or fixed distribution charge of the year used for the basis of the variance. The price variance is the difference calculated on the usage and customer counts of the year times the difference in the distribution variable and fixed rate year over year.

Tables 3 to 7 below attempt to explain the variances, by rate class, outlined in Table 2. While most of the variance is explained, due to having to calculate weighted rates for the calendar year, and harmonizing the Residential rates for comparison purposes, some differences exist; however, overall, the majority of the variance can be explained by the price variance and / or volume variance calculation procedure above.

Distribution Charges – Residential

Table 3
Residential Rate Class – Variance Analysis

	Description	2006 Board Approved	2006 Actual Year	Variance from Board Approved	2007 Actual Year	Variance from 2006 Actual	2008 Actual Year	Variance from 2007 Actual	2009 Bridge Year "Normalized"	Variance from 2008 Actual	2010 Test Year "Normalized"	Variance from 2009 Bridge
	Residential **											
		A	B	C	D	E	F	G	H	I	J	K
	Price Variance			(B1-A1) * A3		(D1-B1) * B3		(F1-D1) * D3		(H1-F1) * F3		(J1-H1) * H3
1	Volumetric Rate *	0.0316	0.0278	(671,203) (B2-A2) * A4*12	0.0318	686,155 (D2-B2) * B4*12	0.0316	(34,759) (F2-D2) * D4*12	0.0314	(34,356) (H2-F2) * F4*12	0.0240	(1,247,036) (J2-H2) * H4*12
2	Fixed Rate *	11.07	10.84	(49,062)	11.14	64,894	11.06	(17,413)	11.01	(10,947)	20.76	2,151,513
	Total Price Variance											
	Volume Variance			(B3-A3) * B1		(D3-B3) * D1		(F3-D3) * F1		(H3-F3) * H1		(J3-H3) * J1
3	kWh Volume	176,632,474	171,538,632	(141,609) (B4-A4) * B2*12	173,795,327	71,763 (D4-B4) * D2*12	171,781,096	(63,650) (F4-D4) * F2*12	168,518,427	(102,448) (H4-F4) * H2*12	169,492,357	23,374 (J4-H4) * J2*12
4	Number of Customers	17,776	18,026	32,520	18,139	15,106	18,245	14,068	18,389	19,025	18,534	36,122
	Total Volume Variance			(829,354)		837,917		(101,754)		(128,726)		963,973

* Rates have been weighted to reflect May 1 as rate effective date
** Rates have been Harmonized for Comparison Purposes to 2010 Test Year

Distribution Charges – G/S < 50 kW

Table 4
G/S < 50 kW Rate Class – Variance Analysis

	Description	2006 Board Approved	2006 Actual Year	Variance from Board Approved	2007 Actual Year	Variance from 2006 Actual	2008 Actual Year	Variance from 2007 Actual	2009 Bridge Year "Normalized"	Variance from 2008 Actual	2010 Test Year "Normalized"	Variance from 2009 Bridge
	G/S < 50 kW	A	B	C	D	E	F	G	H	I	J	K
	Price Variance			(B1-A1) * A3		(D1-B1) * B3		(F1-D1) * D3		(H1-F1) * F3		(J1-H1) * H3
1	Volumetric Rate *	0.0229	0.0208	(117,388) (B2-A2) * A4*12	0.0230	126,065 (D2-B2) * B4*12	0.0229	(5,854) (F2-D2) * D4*12	0.0228	(5,871) (H2-F2) * F4*12	0.0210	(106,319) (J2-H2) * H4*12
2	Fixed Rate *	18.16	16.66	(41,454)	18.27	44,784	18.14	(3,655)	18.06	(2,257)	29.37	319,485
	Total Price Variance											
	Volume Variance			(B3-A3) * B1		(D3-B3) * D1		(F3-D3) * F1		(H3-F3) * H1		(J3-H3) * J1
3	kWh Volume	55,899,141	57,302,192	29,183 (B4-A4) * B2*12	58,537,616	28,415 (D4-B4) * D2*12	58,711,522	3,982 (F4-D4) * F2*12	59,065,949	8,081 (H4-F4) * H2*12	60,923,412	39,007 (J4-H4) * J2*12
4	Number of Customers	2,303	2,318	2,999	2,343	5,481	2,351	1,741	2,354	650	2,357	1,057
	Total Volume Variance			(126,660)		204,744		(3,785)		603		253,230
	* Rates have been weighted to reflect May 1 as rate effective date											

Distribution Charges – G/S 50 to 4999 kW

Table 5
G/S 50 to 4999 kW Rate Class – Variance Analysis

	Description	2006 Board Approved	2006 Actual Year	Variance from Board Approved	2007 Actual Year	Variance from 2006 Actual	2008 Actual Year	Variance from 2007 Actual	2009 Bridge Year "Normalized"	Variance from 2008 Actual	2010 Test Year "Normalized"	Variance from 2009 Bridge
	G/S 50 to 4999 kW	A	B	C	D	E	F	G	H	I	J	K
	Price Variance			(B1-A1) * A3		(D1-B1) * B3		(F1-D1) * D3		(H1-F1) * F3		(J1-H1) * H3
1	Volumetric Rate *	6.0641	5.4583	(212,197) (B2-A2) * A4*12	6.1005	234,988 (D2-B2) * B4*12	6.0575	(14,825) (F2-D2) * D4*12	6.0312	(8,543) (H2-F2) * F4*12	4.9302	(338,275) (J2-H2) * H4*12
2	Fixed Rate *	33.82	30.89	(5,274)	34.02	5,634	33.78	(389)	33.64	(230)	105.91	121,414
	Total Price Variance											
	Volume Variance			(B3-A3) * B1		(D3-B3) * D1		(F3-D3) * F1		(H3-F3) * H1		(J3-H3) * J1
3	kW Volume	350,276	365,911	85,341 (B4-A4) * B2*12	344,767	(128,989) (D4-B4) * D2*12	324,837	(120,726) (F4-D4) * F2*12	307,243	(106,113) (H4-F4) * H2*12	296,554	(52,699) (J4-H4) * J2*12
4	Number of Customers	150	150	-	135	(6,124)	137	811	140	1,211	143	3,813
	Total Volume Variance			(132,131)		105,509		(135,129)		(113,675)		(265,747)
	* Rates have been weighted to reflect May 1 as rate effective date											

Distribution Charges – Sentinel Lights

Table 6
Sentinel Lights Rate Class – Variance Analysis

	Description	2009 Bridge Year "Normalized"	2010 Test Year "Normalized"	Variance from 2009 Bridge
	Sentinel Lights			
		A	B	C
	Price Variance			(B1-A1) * A3
1	Volumetric Rate *	4.6898	19.0586	17,860
				(B2-A2) * A4*12
2	Fixed Rate *	1.71	7.39	42,055
	Total Price Variance			
	Volume Variance			(B3-A3) * B1
3	kW Volume	1,243	1,167	(1,448)
				(B4-A4) * B2*12
4	Number of Connections	617	589	(2,483)
	Total Volume Variance			55,984
	* Rates have been weighted to reflect May 1 as rate effective date			

Distribution Charges – Street Lighting

Table 7
Street Lighting Rate Class – Variance Analysis

	Description	2009 Bridge Year "Normalized"	2010 Test Year "Normalized"	Variance from 2009 Bridge
	Street Lighting			
		A	B	C
	Price Variance			(B1-A1) * A3
1	Volumetric Rate *	4.1066	9.9657	37,938
				(B2-A2) * A4*12
2	Fixed Rate *	1.51	3.89	82,224
	Total Price Variance			
	Volume Variance			(B3-A3) * B1
3	kW Volume	6,475	6,475	-
				(B4-A4) * B2*12
4	Number of Connections	2,879	2,879	-
	Total Volume Variance			120,162
	* Rates have been weighted to reflect May 1 as rate effective date			

The variance in the Embedded Distributor Rate Class for HONI is solely attributed to the non-existence of this rate class prior to 2010. This "new proposed" rate class forms part of HCHI's 2010 Rate Application as discussed in Exhibit 1, Tab 1, Schedule 12 with "proposed" rates effective May 1, 2010 detailed in Exhibit 8, Tab 1, Schedule 1.

HCHI's existing Embedded Distributor rate class distribution wheeling service rate revenue applicable only to Norfolk Power Distribution Inc. ("NPI") has been allocated to Other Distribution Revenue as revenue offset as listed in Note #1 to Table 1 above. This revenue is forecast to decline into the 2009 Bridge year with complete elimination by the end of the 201 test year. This is due to the elimination of load at one feeder as at December 31, 2008 and with the other feeder expected to be eliminated by the end of 2010. The loss of embedded distribution revenue from NPI is discussed in further detail following this Table 8.

Distribution Charges – Embedded Distributor

Table 8
Embedded Distributor Rate Class – Variance Analysis

	Description	2009 Bridge Year "Normalized"	2010 Test Year "Normalized"	Variance from 2009 Bridge
	Embedded Distributor			
		A	B	C
	Price Variance			(B1-A1) * A3
1	Volumetric Rate *	-	0.5610	-
				(B2-A2) * A4*12
2	Fixed Rate *	-	191.77	-
	Total Price Variance			
	Volume Variance			(B3-A3) * B1
3	kW Volume	-	276,949	155,368
				(B4-A4) * B2*12
4	Number of Connections	-	8	18,410
	Total Volume Variance			173,778
	* Rates have been weighted to reflect May 1 as rate effective date			

Embedded Distributor – Norfolk Power Distribution Inc.

A "Monthly Distribution Wheeling Service Rate – Norfolk Power" was first approved by the OEB to be effective May 1, 2006. At that time HCHI lines were used to supply NPI at the following two metering points:

- Jarvis TS 57M4 at Concession 6 (discontinued on December 12, 2008), and
- Jarvis TS 57M4 at Highway 6.

On December 12, 2008 Norfolk Power Distribution Inc. ("NPI") eliminated its need for supply at Concession 6 prompting HCHI to write a letter dated December 30, 2008 requesting NPI's intent with respect to the other supply at Highway 6. NPI replied by letter dated January 6, 2009 stating their intent to "*… discontinue our feed from Jarvis TS by the end of 2010*", however, their letter is not specific in terms of when during 2010 their load may be eliminated. Both HCHI's letter and NPI's reply are attached to this Schedule as Appendix A.

Table 9 below provides the history of service to this rate class and its revenue variance from 2006 Board Approved.

Table 9
Embedded Distributor – Norfolk Power

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge Year	2010 Test Year
Revenue	$74,493	$54,749	$82,276	$73,448	$42,853	$42,207
kW Volume	119,532	87,851	131,213	117,976	69,128	68,065
No. of Customers	1	1	1	1	1	1
No. of Supply Points	2	2	2	2	1	1
Price ($/kW)	$0.6232	$0.6232	$0.6288	$0.6194	$0.6201	$0.6201
Revenue Variance from 2006 Board Approved	0	($19,744)	$7,783	($1,156)	($31,640)	

HCHI proposes that the existing "Monthly Distribution Wheeling Service Rate – Norfolk Power" be continued at $0.6201 per kW resulting in a revenue forecast of up to $42,207 during the 2010 Test year. This would support the recovery of the lost revenue as illustrated in the above Table 9 which sets out accumulated variance of $44,757 from the 2006 Board Approved to the 2009 Bridge year.

In view of NPI's stated intent in their letter dated January 6, 2009, to "*… discontinue our feed from Jarvis TS by the end of 2010*", it is further proposed that the uncertain 2010 revenue be excluded from HCHI's revenue requirement and used to offset the loss incurred by HCHI for this rate class since 2006. This loss is mostly due to NPI's elimination of one supply point on December 12, 2008.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

HCHI has calculated its load and revenue forecasts with a load forecasting model that uses multifactor regressions in accordance with the Filing Requirements. After HCHI's review of the various processes used by the 2008 and the 2009 cost of service applicants, HCHI chose to adopt a weather normalization forecasting method similar to the one used by Toronto Hydro Electric System Ltd. in its rate applications for 2008, 2009 and 2010 (EB-2007-0680). A similar method was used by the following 2009 cost of service applicants, most of which have been approved by the Board at the time of this filing:

1. Greater Sudbury Hydro Inc.
2. Innisfil Hydro Distribution Systems Ltd.
3. Lakeland Power Distribution Ltd.
4. London Hydro Inc.
5. Niagara-on-the-Lake Hydro Inc.
6. Thunder Bay Hydro Electricity Distribution Inc.

In summary, HCHI has used the same regression analysis methodology used by the distributors mentioned above to determine a prediction model, but has altered the method for the 2009 and 2010 load forecasts by including information provided in the IESO's *18-Month Outlook for June 2009 to November 2010* dated May 25, 2009 ("IESO 18-Month Outlook") with the interim update published by the IESO on August 5, 2009.

During the review process of the 2009 cost of service rate applications, Intervenors have expressed concerns with the load forecasting weather process being proposed by certain of the applicants. Intevenors have suggested that the weather normalization should be conducted on an individual rate class basis and the regression analysis would be based on monthly billed kWh by rate class. In HCHI's view, conducting a regression analysis which relates what the monthly billed kWh of a class is to other monthly

variables is problematic. The monthly billed amount is not the amount consumed in the month but rather the amount billed. The amount billed is based on billing cycle meter reading schedules whose reading dates vary and typically are not at month end. The amount billed could include consumption from the month before or even further back. By using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be logical, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In HCHI's view, variables such as heating degree days impact the amount consumed not the amount billed. It is possible to estimate the amount consumed in a month based on the amount billed, but until such time as smart meters are fully deployed this would only be an estimate which in HCHI's view would reduce the accuracy of a regression model that is based on monthly billing data. In addition, HCHI does not have as many years of monthly historical billed data by rate class as it does for the amount purchased. As a result, conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

HCHI understands that to a certain degree the process of developing a load forecast for a cost of service rate application is an evolving science for electricity distributors in the Province. HCHI's view on the overall process of load forecasting is that conducting a regression analysis on historical purchases to produce an equation that will predict purchases is appropriate, and by proposing to incorporate information from the IESO 18-Month Outlook HCHI has refined the method to some extent. HCHI expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by considering data provided from smart meters and how other distributors are conducting load forecasts. However, based on the OEB's approval of the current methodology in a number of 2009 rate applications, HCHI submits that the load forecasting methodology HCHI has incorporated into this cost of service rate application is reasonable at this time.

HCHI has available data for the exact amount of kWh purchased from the IESO and embedded generators on a wholesale basis in order to supply to HCHI's retail customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the monthly purchases based on those explanatory variables. The prediction model is then used as the basis to forecast the total level of weather normalized purchases for HCHI's 2009 Bridge year and 2010 Test year. The weather normalized purchases are converted to billed kWh by rate class.

Historical data used for purchased consumption was for the periods 2001 to 2008 and for billed consumption was for the periods 2002 to 2008. HCHI is an amalgamated utility of the hydro-electric commissions of the former municipalities of Haldimand and Dunnville and divided city of Nanticoke, with an incorporation date of October 13, 2000, commencing distribution operations on November 1, 2000. Historical records prior to November 1, 2000 were not available to be used in the regression analysis, thus actual annual purchased consumption was only available from January 1, 2001 to December 31, 2008. Historical information on the billed side was only available back to January 1, 2002 summarized by the rate classes that are currently in existence. In addition, the General Service classes were separated into "50 to 4999 kW" and "less than 50 kW" as a result of rate unbundling first implemented in 2002.

Tables 10, 11, and 12 below provide summaries of the weather normalized load and customer / connection forecast used in this application. 2002 to 2008 are weather actual and 2009 and 2010 are weather normalized. HCHI currently does not have a process to adjust weather actual data to a weather normal basis. However, the forecast data for 2009 and 2010 has been calculated on a weather normalized basis.

A detailed explanation of this process is provided later in this Exhibit.

The Embedded Distributor rate class applicable to NPI has been excluded from these tables. The new embedded distributor, HONI, provided HCHI with an existing load forecast that had been previously used by HONI for their own purposes – in order that HCHI forecast the seven embedded supply points for calculation of the embedded rate in this 2010 rate application. The eighth supply point load at Air Products was based on HONI's customer forecast of load for this new embedded point. The NPI embedded point is excluded from this analysis as discussed previously in this Exhibit at Tab 2, Schedule 1.

Table 10
Summary of Load and
Customer / Connection Forecast

Year	Billed (kWh)	Growth (kWh)	Percent Change	Customer / Connection Count	Growth	Percent Change
2002	352,096,966			23,472		
2003	358,594,281	6,497,315	1.85%	23,682	210	0.89%
2004	362,334,202	3,739,921	1.04%	23,816	134	0.57%
2005	373,431,335	11,097,133	3.06%	23,936	120	0.50%
2006	359,311,281	(14,120,054)	-3.78%	24,033	97	0.41%
2007	360,337,098	1,025,817	0.29%	24,160	127	0.53%
2008	352,084,249	(8,252,849)	-2.29%	24,343	183	0.76%
2009 Normalized	344,138,036	(7,946,213)	-2.26%	24,463	120	0.49%
2010 Normalized	343,105,622	(1,032,414)	-0.30%	24,586	123	0.50%

Note: Customer and Connection counts are as at Year-End (December 31st)

The streetlights, sentinel lights and unmetered scattered loads are measured as connections.

Actual and forecasted billed amounts and number of customers by rate class are shown in Table 11 below.

Table 11
Billed Energy and Number of Customers by Rate Class

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads	Total
Energy (kWh)							
2002	177,417,290	51,517,777	120,066,374	483,480	2,101,680	510,365	352,096,966
2003	175,021,556	58,877,719	121,347,276	587,864	2,220,905	538,961	358,594,281
2004	172,248,238	56,982,950	129,791,532	572,369	2,191,755	547,358	362,334,202
2005	181,464,305	59,292,994	129,442,860	539,685	2,177,588	513,903	373,431,335
2006	171,538,632	57,302,192	127,213,861	516,624	2,232,308	507,664	359,311,281
2007	173,795,327	58,537,616	124,717,255	489,923	2,297,657	499,320	360,337,098
2008	171,781,096	58,711,522	118,305,016	475,594	2,328,757	482,264	352,084,249
2009 Normalized	168,518,427	59,065,949	113,296,507	446,132	2,328,757	482,264	344,138,036
2010 Normalized	169,492,357	60,923,412	109,459,903	418,928	2,328,757	482,264	343,105,621
Number of Customers / Connections							
2002	17,407	2,306	138	859	2,673	89	23,472
2003	17,585	2,288	151	857	2,713	88	23,682
2004	17,776	2,303	150	729	2,777	81	23,816
2005	17,893	2,330	151	705	2,764	93	23,936
2006	18,026	2,318	150	693	2,758	88	24,033
2007	18,139	2,343	135	665	2,794	84	24,160
2008	18,245	2,351	137	647	2,879	84	24,343
2009	18,389	2,354	140	617	2,879	84	24,463
2010	18,534	2,357	143	589	2,879	84	24,586

Table 12 summarizes the annual usage per customer / connection by rate class.

Table 12
Annual Usage per Customer/Connection by Rate Class

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads
Energy Usage (kWh) per Customer / Connection						
2002	10,192	22,341	2,947,132	563	786	5,734
2003	9,953	25,733	3,482,472	686	819	6,125
2004	9,690	24,743	3,582,000	785	789	6,758
2005	10,142	25,448	3,471,737	766	788	5,526
2006	9,516	24,721	3,493,188	745	809	5,769
2007	9,581	24,984	2,376,253	737	822	5,944
2008	9,415	24,973	2,101,728	735	809	5,741
2009 Normalized	9,292	25,441	1,987,658	723	809	5,741
2010 Normalized	9,170	25,918	1,880,056	711	809	5,741
Annual Growth Rate in Usage per Customer / Connection						
2002						
2003	-2.34%	15.18%	18.16%	21.85%	4.20%	6.82%
2004	-2.64%	-3.85%	2.86%	14.43%	-3.66%	10.33%
2005	4.66%	2.85%	-3.08%	-2.42%	-0.13%	-18.23%
2006	-6.17%	-2.86%	0.62%	-2.74%	2.66%	4.40%
2007	0.68%	1.06%	-31.97%	-1.07%	1.61%	3.03%
2008	-1.73%	-0.04%	-11.55%	-0.27%	-1.58%	-3.42%
2009 Normalized	-1.31%	1.87%	-5.43%	-1.63%	0.00%	0.00%
2010 Normalized	-1.31%	1.87%	-5.41%	-1.66%	0.00%	0.00%

Street Lighting and Unmetered Scattered Loads have been forecast not to change from the 2008 usage levels. HCHI does not foresee any additional connections or loss of connections from these two rate classes in the 2010 Test year. As well, the Sentinel

Light rate class has been experiencing a decline in connections due to the removals of lights in a given year exceeding the installation of new lights in that same year. The G/S 50 to 4999 kW rate class has also experienced a decline in consumption from 2006 through 2008. This is due to the loss of two of the larger customers that were interval metered, one part way through 2006 and the other part way through 2007.

LOAD FORECAST AND METHODOLOGY

HCHI reviewed the IESO's 18-Month Outlook, as mentioned above, in preparing the load forecast and is proposing to use the results of this report in the 2009 and 2010 load forecast. In particular, HCHI noted the following statements from the "Executive Summary" page iii of the report:

"The economic downturn that began last fall has triggered a noteworthy drop in demand for electricity across North America. In Ontario, peak and energy demand have declined in recent months, in part, as wholesale industrial consumers have scaled back on consumption. Over the first three months of the year, wholesale industrial consumption of electricity dropped by approximately 20 per cent compared with the same period in 2008. Other factors affecting demand are the growth in embedded generation and the impacts of conservation. Although the North American economy is expected to recover in 2010, electricity demand is unlikely to recover within the Outlook period. Overall, electricity demand in Ontario is expected to decline by 4.0 per cent in 2009 and 0.3 per cent in 2010…

In recent months, supply and demand conditions contributed to periods of surplus baseload generation (SBG) from late March to mid-April 2009. These periods were accompanied by record low negative prices. A confluence of factors led to these conditions:

- *Low demand due to the economic downturn, increased conservation and embedded generation, and relatively mild spring weather*

- *High availability and output of baseload generation, including nuclear, wind and hydroelectric generation driven by spring freshet (or snow melt)*
- *Planned transmission outages, including an outage on the New York interconnection, which significantly reduced Ontario's export capability…"*

In regards to the IESO's Ontario Demand Forecast, the IESO 18-Month Outlook states in the "Conclusions & Observations" section of the report on page v:

> *"The current recession has significantly reduced electricity demand on the system. Both energy and peak demands are tracking much lower than a year ago. Although the economy is expected to recover in 2010, electricity demand will not due to structural change in the Ontario economy, higher levels of conservation and continuing growth in embedded generation."*

The following Table 3.1 is an excerpt from the IESO 18-Month Outlook, and shows the seasonal peaks and annual energy demand over the forecast horizon.

IESO 18-Month Outlook - Ontario Demand Forecast

Table 3.1 Forecast Summary from IESO Document - IESO_REP_0549v1.0 May 25, 2009

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2009	24,351	26,454
Winter 2009-10	22,886	24,046
Summer 2010	24,160	26,348
Year	Normal Weather Energy (TWh)	% Growth in Energy
2006 Energy	152.3	-1.9%
2007 Energy	151.6	-0.5%
2008 Energy	148.9	-1.8%
2009 Energy (Forecast)	142.9	-4.0%
2010 Energy (Forecast)	142.5	-0.3%

HCHI has included the above information in its weather normalizing load forecasting process. HCHI's weather normalized load forecast is developed in a four-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, and economic data. The regression analysis produces an equation that predicts power purchases based on the explanatory variables used in the regression analysis. The equation is used to predict 2008 power purchases under weather normal conditions. Second, the predicted 2008 weather normal purchases are adjusted by the negative growth factors outlined in the IESO 18-Month Outlook, as provided in the above table, to produce a 2009 and 2010 forecast of weather normal purchases. Third, the weather normalized purchased energy forecast is adjusted by HCHI's "proposed" total loss factor – as developed by Kinectrics and discussed in detail in Exhibit 8, Tab 1, Schedule 4 – to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer.

For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric analysis of the historical data and a separate analysis of the growth in specific customer rate classes (street lighting and unmetered scattered loads). The geometric analysis of the G/S < 50 kW customer class and the G/S 50 to 4999 kW customer class only captured historical data for the period to period changes from 2002 to 2006 as a result of the reclassification of General Service customers that was first required in 2006. This reclassification distorted the geometric analysis and produced uncharacteristic growth in those two rate classes. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy (kWh) forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (Ontario Real GDP growth), load characteristics (peak hours per month), population, number of customers, and calendar variables (days in month, seasonal). The regression model uses monthly kWh and monthly values of independent variables from January 2001 to December 2008 to determine the monthly regression coefficients. Once the predicted purchases are determined based on actual weather, the 2008 data is weather normalized using an average of the eight years (2001 to 2008) heating and cooling degree days to produce weather-normalized predicted purchases for January to December 2008.

To forecast the 2009 and 2010 weather-normalized purchases, HCHI has incorporated the IESO 18-Month Outlook as explained above. The IESO is forecasting a 4.0% decline in Ontario energy demand for the year 2009 and an additional 0.3% decline for the year 2010. HCHI has chosen to incorporate this IESO 18-Month Outlook as the majority of HCHI's wholesale consumption is purchased through the IESO; as well, HCHI has experienced a decline in retail and wholesale consumption (kWh) since 2007 and into 2009. When comparing June 2009 results to June 2008 results, HCHI records retail consumption (billed plus estimate of unbilled) as at June 30, 2009 of 164,821,368 kWh as compared to the same period as at June 30, 2008 of 173,211,689 kWh – a 4.8% decrease.

As discussed in the opening summary of this Tab 2 Schedule 2, HCHI only has data available for our total system load as far back as January 2001. This provides 96 monthly data points to December 2008, which is a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard, it is HCHI's view that it is appropriate to review the impact of weather since 2001 on the energy usage and then determine the average weather

conditions from 2001 to 2008 which is then applied to 2008 data to determine a 2008 weather normalized predicted purchases. The IESO 18-Month Outlook forecast is then applied to 2009 and 2010 to determine a weather normalized forecast. This process was discussed in further detail in the paragraph above.

The multifactor regression model has determined primary drivers of year-over-year changes in HCHI's load growth as economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Economic growth – which encompasses both population trends and customer base growth in HCHI's service territory as well as general economic conditions – are captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP"), population statistics, and customer numbers.

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 remaining factors determining energy use in the monthly model can be classified as calendar variables and load characteristics. For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month, hours of peak load in a month, and "flag" variables to capture the typically lower usage in the spring and fall months and the higher usage in the summer months, as apparent in HCHI's historical usage.

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Using stepwise regression techniques, different explanatory variables were tested, with the ultimate model being determined both by model statistics and by forecast accuracy.

The model chosen as the best predictor of kWh purchased by HCHI is as follows:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.962788755
R Square	0.926962187
Adjusted R Square	0.918369503
Standard Error	896140.1964
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	10	8.66333E+14	8.66333E+13	107.8780742	6.37209E-44
Residual	85	6.82607E+13	8.03067E+11		
Total	95	9.34594E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-79176799.3	30812879.85	-2.569600754	0.011925697	-140441058.2	-17912540.37	-140441058.2	-17912540.37
Heating Degree Days	10282.86808	790.2377682	13.01237234	6.21321E-22	8711.663714	11854.07244	8711.663714	11854.07244
Cooling Degree Days	68861.43045	5357.752782	12.85267037	1.25115E-21	58208.78275	79514.07815	58208.78275	79514.07815
Ontario Real GDP Monthly %	-253251.3803	112373.5529	-2.253656432	0.02679113	-476680.1048	-29822.65577	-476680.1048	-29822.65577
Number of Days in Month	995494.2545	122707.6883	8.112729268	3.35757E-12	751518.5006	1239470.008	751518.5006	1239470.008
Spring / Fall Flag	-2679843.76	361761.2102	-7.407769779	8.67075E-11	-3399121.95	-1960565.57	-3399121.95	-1960565.57
Number of Customers	11528.78802	1613.568139	7.14490311	2.8775E-10	8320.582331	14736.9937	8320.582331	14736.9937
Population	-2766.999097	1011.672215	-2.735074716	0.007589664	-4778.474456	-755.5237377	-4778.474456	-755.5237377
Number of Peak Hours	1400.268096	6256.131019	0.223823333	0.823431861	-11038.59619	13839.13238	-11038.59619	13839.13238
Blackout Flag	-600836.4469	933608.4264	-0.64356365	0.521591032	-2457100.083	1255427.189	-2457100.083	1255427.189
Summer Months Flag	-1717382.049	618747.441	-2.775578427	0.006775487	-2947617.704	-487146.3931	-2947617.704	-487146.3931

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix B.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree day information. Hamilton Airport weather station data was used;

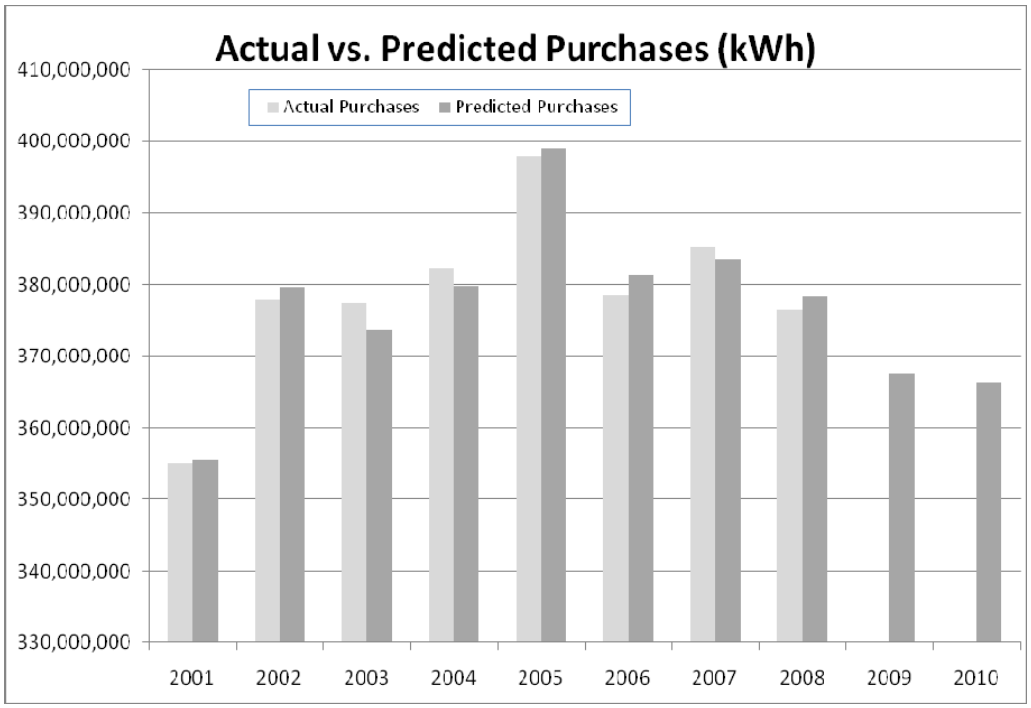
b) The Ontario real GDP monthly index numbers came from the Ontario Ministry of Finance's "*Ontario Economic Outlook and Fiscal Review*" (2001 to 2007 from the 2003 and 2008 Outlook, and 2008 to 2010 from the 2009 Outlook);

c) Population data was based on the 2006 Census population data for Haldimand County with growth adjustments of 400 per year based on a report from Haldimand County "*Population, Employment and Household Forecasts to 2031*"; and

d) The calendar provided information related to number of days in the month, number of peak hours, the spring/fall flag, and the summer flag.

The annual results of the above prediction formula compared to the actual annual purchases from 2001 to 2008 as well as the result of the prediction formula for 2009 and 2010 are shown in the chart below. The prediction formula has a statistical R^2 of 92% which generally indicates the formula has a very good fit to the actual data set.

Chart
Actual vs. Predicted Purchases (kWh)



The following Table 13 outlines the data that supports the "Actual vs. Predicted Purchases" Chart above.

Table 13
Total System Purchases

Year	Actual kWh	Predicted kWh	% Variation
2001	355,113,677	355,495,365	0.11%
2002	377,889,868	379,556,929	0.44%
2003	377,328,535	373,668,716	(0.97)%
2004	382,256,439	379,761,179	(0.65)%
2005	397,949,707	399,017,639	0.27%
2006	378,534,757	381,188,764	0.70%
2007	385,126,910	383,524,291	(0.42)%
2008	376,481,614	378,468,624	0.53%
2009 (WN)		367,539,422	
2010 (WN)		366,436,804	

The method used to forecast the 2009 and 2010 weather normalized amounts was detailed above in the opening paragraphs of the section "Purchased kWh Load Forecast". No further adjustments have been made for CDM activities since HCHI has incorporated the IESO 18-Month Outlook into its load forecasting model which accounts for energy savings on account of CDM initiatives.

HCHI has done an analysis of load forecast models based on using a 10-year average of monthly heating degree days ("HDD") and monthly cooling degree days ("CDD"), a trend based on 20-years of HDD and CDD, and the method used in HCHI's model of calculating the average weather conditions, HDD and CDD, from 2001 to 2008. All three of these methods were then applied to the 2008 data to determine 2008 weather normalized predicted purchases. This 2008 weather normalized information was further adjusted by the IESO 18-monthly Outlook decreases to predict 2009 and 2010 weather

normalized purchases. HCHI has chosen to remain with the original model using the 8-year average of HDD and CDD for a couple of reasons. Firstly, the other two methods did not produce significant variances in the resulting billed consumption and secondly, the other two methods produced a lower billed consumption which would result in more significant bill impacts to the customers overall in order to recover HCHI's revenue requirement. The following Table 14 illustrates the results of the three methods:

Table 14
2010 Test Year Comparison of Load Forecast Models (HDD & CDD Methods)

HDD / CDD Method	Purchased Consumption	Loss Factor	Billed Consumption	HCHI Model Comparison
HCHI 8-Year Average (2001 to 2008)	366,436,804	1.0680	343,105,622	
10-Year Average (1999 to 2008)	366,244,432	1.0680	342,925,498	(180,124)
20-Year Trend (1989 to 2008)	363,982,339	1.0680	340,807,433	(2,298,189)

HCHI has included all three load forecast models, in excel format, as part of the 2010 rate application filing as now required in the Filing Requirements.

The details on the average monthly heating degree days and cooling degree days that HCHI incorporated into the model are shown in Appendix C, along with the 10-year average of HDD and CDD and the 20-year trend of HDD and CDD, also as required in the Filing Guidelines.

Billed kWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by the "proposed" total loss factor of

1.0680, as calculated by a third party consultant, Kinectrics, and detailed in Exhibit 8, Tab 1, Schedule 4.

Applying this total loss factor ("TLF"), the total weather normalized billed energy will be 344,138,036 kWh for 2009 (i.e. 367,539,422 purchased kWh / 1.0680) and 343,105,622 kWh for 2010 (i.e. 366,436,804 purchased kWh / 1.0680).

Billed kWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes, taking into consideration the customer / connection forecast and expected usage per customer 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 for the past 7 years, 2002 to 2008, as shown in Table 15.

Table 15
Historical Customer / Connection Data

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads	Total
Number of Customers / Connections							
2002	17,407	2,306	138	859	2,673	89	23,472
2003	17,585	2,288	151	857	2,713	88	23,682
2004	17,776	2,303	150	729	2,777	81	23,816
2005	17,893	2,330	151	705	2,764	93	23,936
2006	18,026	2,318	150	693	2,758	88	24,033
2007	18,139	2,343	135	665	2,794	84	24,160
2008	18,245	2,351	137	647	2,879	84	24,343
Geomean Annual Growth Rate	1.0079	1.0013	1.0211	0.9539			

The geometric mean was determined to be appropriate as an estimator of the 2009 and 2010 customer/connection counts for the majority of the rate classes as shown in the above Table 15. The Sentinel Light rate class is forecasted to decline in 2009 and 2010 based on historical removals exceeding any additions. However, for the Street Lighting rate class and Unmetered Scattered Load rate class it was determined that the number of connections should remain constant at the 2008 level; that is, no projection for additional connections in 2009 or 2010.

The resulting geometric mean is applied to the 2008 customer/connection numbers to determine the forecast of customer/connections for 2009 and 2010 for all classes except Street Lighting and Unmetered Scattered Load as mentioned above. Table 16 outlines the forecast of customers by rate class for 2009 and 2010.

Table 16
Customer / Connection Forecast

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads	Total
Forecast Number of Customers / Connections							
2009	18,389	2,354	140	617	2,879	84	24,463
2010	18,534	2,357	143	589	2,879	84	24,586

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following Table 17 provides the average annual usage per customer/connection by rate class for the past 7 years, 2002 to 2008.

Table 17
Historical Annual Usage per Customer / Connection

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads
Energy Usage (kWh) per Customer / Connection						
2002	10,192	22,341	2,947,132	563	786	5,734
2003	9,953	25,733	3,482,472	686	819	6,125
2004	9,690	24,743	3,582,000	785	789	6,758
2005	10,142	25,448	3,471,737	766	788	5,526
2006	9,516	24,721	3,493,188	745	809	5,769
2007	9,581	24,984	2,376,253	737	822	5,944
2008	9,415	24,973	2,101,728	735	809	5,741
Geomean Annual Growth Rate	0.9869	1.0187	0.9452	0.9837		

Usage per customer/connection can only be determined for 2002 and onward since historical billed energy by rate class is only available from 2002; that is, 2001 information detailed by all rate classes is not available. As viewed in the above Table 17, usage per customer/connection essentially declines for all classes except the G/S < 50 kW which can be attributed to the reclassification of customers from the G/S 50 kW to 4999 rate class.

For the forecast of usage per customer/connection, the historical geometric mean was used for all rate classes except Street Lighting and Unmetered Scattered Loads for the same reasons as discussed in the customer/connection forecast above; that is, to be held constant at the 2008 levels. For Sentinel Lights, the geometric mean was calculated on 4 years of data instead of 7 years due to the accuracy of the data in the earlier years. If HCHI had used 7 years in the calculation, the usage/connection would be increasing which does not reflect an accurate forecast for 2009 and 2010 since the historical pattern suggests connections are actually declining year over year. The forecasted usage by rate class is set out in Table 18 below.

Table 18
Forecast Annual kWh Usage per Customer / Connection

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads
Forecast Annual Energy Usage (kWh) per Customer / Connection						
2009	9,292	25,441	1,987,658	723	809	5,741
2010	9,170	25,918	1,880,056	711	809	5,741

With the preceding information, the non-normalized weather billed energy forecast can be determined by applying the forecast number of customer/connection from Table 16 to the forecast of annual usage per customer/connection from Table 18. The resulting non-normalized weather billed energy forecast is shown in Table 19 below.

Table 19
Non-Normalized Weather Energy Forecast

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads	Total
Forecast Annual Non-Normalized Energy Usage (kWh)							
2009	170,863,591	59,887,932	113,866,224	446,132	2,328,757	482,264	347,874,900
2010	169,949,734	61,087,815	109,566,912	418,928	2,328,757	482,264	343,834,410

The non-normalized weather billed energy forecast has been determined as set out in Table 19 above but needs to be adjusted for weather sensitive load in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 344,138,036 kWh for 2009 and 343,105,621 kWh for 2010 as detailed by rate class in Table 11.

The difference between the non-normalized and normalized forecast is 3,736,864 kWh in 2009 and 728,789 kWh in 2010. This difference will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One Networks Inc., on behalf of HCHI for the cost allocation study

filed in February 2007 with the OEB, the weather sensitivity by rate classes was determined as set out in Table 20 below.

Table 20
Weather Sensitivity by Rate Class

Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads
Weather Sensitivity					
100%	100%	36%	0%	0%	0%

The Residential and G/S < 50 kW rate classes are considered to be 100% weather sensitive and the Sentinel Lights, Street Lighting, and Unmetered Scattered Loads rate classes are considered to be 0% weather sensitive. Hydro One Networks Inc. determined the G/S 50 to 4999 kW Non-interval Metered class to be 58% weather sensitive and the G/S 50 to 4999 kW Interval Metered class to be 29% weather sensitive. These two classes were kept separate in the load forecasting model, Appendix B, but have been combined for purposes of the tables in this Exhibit. The G/S 50 to 4999 kW class was split into the two categories to determine the forecasted load for each group of customers, interval metered and non-interval metered, in order to maintain separate Retail Transmission Service Rates that are applicable to the two groups. Therefore, when combining the kWh usage for the two separate G/S 50 to 4999 kW grouping, the weather sensitive load calculates to be 36% as in the above table.

The difference between the non-normalized and normalized forecast has been assigned on a prorated basis to each rate class based on the above level of weather sensitivity. The following Table 21 indicates how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast.

Table 21
Alignment of Non-Normalized to Weather-Normalized Energy Forecasts

Year	Residential	G/S < 50 kW	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Loads	Total
Forecast Annual Non-Normalized Energy Usage (kWh)							
2009	170,863,591	59,887,932	113,866,224	446,132	2,328,757	482,264	347,874,900
2010	169,949,734	61,087,815	109,566,912	418,928	2,328,757	482,264	343,834,410
Adjustment for Weather (kWh)							
2009	(2,345,164)	(821,983)	(569,717)	0	0	0	(3,736,864)
2010	(457,377)	(164,403)	(107,009)	0	0	0	(728,789)
Forecast Annual Weather-Normalized Energy Usage (kWh)							
2009	168,518,427	59,065,949	113,296,507	446,132	2,328,757	482,264	344,138,036
2010	169,492,357	60,923,412	109,459,903	418,928	2,328,757	482,264	343,105,621

Billed kW Load Forecast

There are a number of rate classes where the distribution volumetric charge billing determinant is on a per kW basis. These include General Service 50 to 4999 kW, Street Lighting and Sentinel Lights. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following Table 22 provides the annual demand units by applicable rate class for the years 2002 to 2008.

Table 22
Historical Annual kW per Applicable Rate Class

Year	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting
Annual (kW) per Rate Class			
2002	331,604	1,343	5,838
2003	329,795	1,718	6,047
2004	362,779	1,578	6,089
2005	363,880	1,482	5,668
2006	365,911	1,423	6,222
2007	344,767	1,361	6,403
2008	324,837	1,313	6,475

The following Table 23 provides the corresponding kWh data.

Table 23
Historical Annual kWh per Applicable Rate Class

Year	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting
Annual (kWh) per Rate Class			
2002	120,066,374	483,480	2,101,680
2003	121,347,276	587,864	2,220,905
2004	129,791,532	572,369	2,191,755
2005	129,442,860	539,685	2,177,588
2006	127,213,861	516,624	2,232,308
2007	124,717,255	489,923	2,297,657
2008	118,305,016	475,594	2,328,757

The following Table 24 provides the calculated historical ratio of kW / kWh as well as the average ratio for the period, 2002 to 2008.

Table 24
Historical kW / kWh Ratio per Applicable Rate Class

Year	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting
kW / kWh Ratio per Rate Class			
2002	0.2762%	0.2778%	0.2778%
2003	0.2718%	0.2922%	0.2723%
2004	0.2795%	0.2757%	0.2778%
2005	0.2811%	0.2746%	0.2603%
2006	0.2876%	0.2754%	0.2787%
2007	0.2764%	0.2778%	0.2787%
2008	0.2746%	0.2761%	0.2780%
Average	0.2782%	0.2748%	0.2785%

The average ratio was applied to the weather normalized billed energy forecast for 2009 and 2010 to provide the forecast of kW for the applicable rate classes as shown in Table 25 below.

Table 25
Forecast of kW by Applicable Rate Class

Year	G/S 50 to 4999 kW	Sentinel Lights	Street Lighting
Forecast Annual (kW) per Rate Class			
2009	307,243	1,243	6,475
2010	296,554	1,167	6,475

The following Table 26 summarizes the consumption and customer /connection data for each rate class for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, and weather normalized 2009 Bridge year and 2010 Test year.

Table 26
Summary of Forecast Data

		2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge Year Weather Normalized	2010 Test Year Weather Normalized
Customer Class:							
Residential							
Customers	Customers	17,776	18,026	18,139	18,245	18,389	18,534
kWh	Consumption - kWh	176,632,472	171,538,632	173,795,327	171,781,096	168,518,427	169,492,357
General Service < 50 kW							
	Customers	2,303	2,318	2,343	2,351	2,354	2,357
	Consumption - kWh	55,899,141	57,302,192	58,537,616	58,711,522	59,065,949	60,923,412
General Service 50 to 4999 kW							
	Customers	150	150	135	137	140	143
	Consumption - kWh	126,947,371	127,213,861	124,717,255	118,305,016	113,296,507	109,459,903
	Demand - kW	350,276	365,911	344,767	324,837	307,243	296,554
Sentinel Lights							
	Connections	729	693	665	647	617	589
	Consumption - kWh	494,247	516,624	489,923	475,594	446,132	418,928
	Demand - kW	1,393	1,423	1,361	1,313	1,243	1,167
Street Lighting							
	Connections	2,777	2,758	2,794	2,879	2,879	2,879
	Consumption - kWh	2,216,168	2,232,308	2,297,657	2,328,757	2,328,757	2,328,757
	Demand - kW	6,115	6,222	6,403	6,475	6,475	6,475
Unmetered Scattered Loads							
	Connections	81	88	84	84	84	84
	Consumption - kWh	502,646	507,664	499,320	482,264	482,264	482,264
Total (Excluding Embedded Distributor)							
	Customers / Connections	23,816	24,033	24,160	24,343	24,463	24,586
	Consumption - kWh	362,692,045	359,311,281	360,337,098	352,084,249	344,138,036	343,105,621
	Demand - kW	357,784	373,556	352,531	332,625	314,961	304,196
Embedded Distributor - HONI							
Customers		0	0	0	0	8	8
kWh		0	0	0	0	81,924,442	83,184,875
kW		0	0	0	0	274,235	276,949

OTHER OPERATING REVENUE

Table 27 below summarizes other operating revenues included in HCHI's total revenue requirement. The data in this table provides a breakdown of the "Total Other Revenue" line in Table 1 of this Exhibit.

Table 27

Summary of Other Operating Revenue

Uniform System of Account #	Description	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
4082	Retail Services Revenue	31,819	35,937	31,669	32,268	34,956
4084	Service Transaction Req STR Revenue	1,915	2,132	691	1,020	1,070
4090	Electric Services Incidental to Energy Sales	117,317	144,351	136,928	107,425	107,127
4210	Rent from Electric Property	67,992	69,495	72,444	107,197	79,358
4225	Late Payment Charges	288,988	282,191	292,443	319,125	319,125
4235	Miscellaneous Service Revenues	99,633	145,830	128,495	133,200	133,200
4325	Revenues from Merchandise, Jobbing, Etc.	17,134	23,761	13,868	10,100	10,400
4355	Gain on Disposition of Utility and Other Property	4,529	2,372	16,530	-	-
4360	Loss on Disposition of Utility and Other Property	(4,376)	(713)	(4,641)	-	-
4375	Revenues from Non-Utility Operations	323,139	342,267	355,829	359,823	359,823
4390	Miscellaneous Non-Operating Income	109,625	76,223	81,467	63,140	2,727
4405	Interest and Dividend Income	261,757	266,053	151,971	67,548	67,548
Specific Service Charges		167,625	215,325	200,939	240,397	212,558
Late Payment Charges		288,988	282,191	292,443	319,125	319,125
Other Distribution Revenues		151,051	182,420	169,288	140,713	143,153
Other Income and Expenses		711,808	709,963	615,024	500,611	440,498
TOTAL		**1,319,472**	**1,389,899**	**1,277,694**	**1,200,846**	**1,115,334**

Notes to Table 1, Table 2, Table 27 and Table 28:

1. Account 4210 – Rent from Electric Property has been included in 'Specific Service Charge' operating revenue for accurate comparisons back to the 2006 Board Approved. HCHI's 2006 EDR model as filed with the OEB included account 4210 in 'Specific Service Charge' operating revenue.

2. The following revenue and / or cost accounts associated with deferral and variance accounts and with non-distribution C&DM activities, namely the OPA funded CDM programs, have not been included in Other Operating Revenues:

a) 4405 - OEB Deferred Interest on Deferral and Variance Accounts
b) 4375 - Revenues from Non-Utility Operations – OPA CDM Programs
c) 4380- Expenses on Non-Utility Operations – OPA CDM Programs

The following Table 28 provides a further detailed breakdown for each "Other Distribution Revenue" and "Other Income and Expense" account as summarized in Table 27 above.

Table 28
Detailed Account Breakdown

	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
4082 - Retail Services Revenue					
Service Agreements - One-time Standard Charge	300	400	100	300	300
Service Agreements - Monthly Fixed Charges	1,980	2,460	3,180	1,248	1,056
Service Agreements - Variable Charges	18,907	20,897	17,922	19,200	21,000
Distributor Consolidated "Bill Ready" Billing Charge	10,633	12,180	10,467	11,520	12,600
TOTAL	**31,819**	**35,937**	**31,669**	**32,268**	**34,956**
4084 - Service Transaction Req STR Revenue					
Retail Service Transaction Request (STR's) Charges	1,915	2,132	691	1,020	1,070
TOTAL	**1,915**	**2,132**	**691**	**1,020**	**1,070**
4090 - Electric Services Incidental to Energy Sales					
SSS Administration Charge	62,568	62,075	63,480	64,572	64,920
Distribution Wheeling Service Rate - Norfolk Power Inc.	54,749	82,276	73,448	42,853	42,207
TOTAL	**117,317**	**144,351**	**136,928**	**107,425**	**107,127**
TOTAL "OTHER DISTRIBUTION REVENUE"	**151,051**	**182,420**	**169,288**	**140,713**	**143,153**
4325 - Revenues from Merchandise, Jobbing, Etc.					
Profit from Sale of Services	17,134	23,761	13,868	10,100	10,400
TOTAL	**17,134**	**23,761**	**13,868**	**10,100**	**10,400**
4355 - Gain on Disposition of Utility and Other Property					
Gain on Sale of Capital Assets	4,529	2,372	16,530	-	-
TOTAL	**4,529**	**2,372**	**16,530**	**-**	**-**
4360 - Loss on Disposition of Utility and Other Property					
Loss on Sale/Disposal of Capital Assets	(4,376)	(713)	(4,641)	-	-
TOTAL	**(4,376)**	**(713)**	**(4,641)**	**-**	**-**
4375 - Revenues from Non-Utility Operations					
Administrative Fee for Billing & Collecting Water & Sewer	323,139	342,267	355,829	359,823	359,823
TOTAL	**323,139**	**342,267**	**355,829**	**359,823**	**359,823**
4390 - Miscellaneous Non-Operating Income					
Long Term Load Transfers - Distribution Revenue Portion	93,147	(150,418)	48,155	60,413	
Recovery of Court Awarded Costs incurred in 2003 and 2004 re: HCHI vs Stewart	1,875	1,750	16,750		
Short Term Load Transfers - Distribution Revenue Portion		225,292			
WeirFoulds - Proceeds received on the closing of the Partnership with EnerConnect December 2007			4,781		
ORST Refund - tax paid on invoices for the period January 2005 to August 2008			8,991		
Legal Letter Charges	2,654	2,228	2,104	2,327	2,327
Customer Refunds returned unclaimed and Refunds less than $5.00	1,061	3,565	449	400	400
Recovery of Theft of Power	11,332	388	236		
Billing Adjustments prior March 2002	(444)	(6,583)			
TOTAL	**109,625**	**76,223**	**81,467**	**63,140**	**2,727**
4405 - Interest and Dividend Income					
Bank Deposit Interest	239,422	264,989	128,199	67,548	67,548
Miscellaneous Interest Revenue (GST Refund, Tax Refund, and Early Payment Discounts)	22,335	1,064	23,772	-	-
TOTAL	**261,757**	**266,053**	**151,971**	**67,548**	**67,548**
TOTAL "OTHER INCOME and EXPENSES"	**711,808**	**709,963**	**615,024**	**500,611**	**440,498**

VARIANCE ANALYSIS ON OTHER OPERATING REVENUE

The materiality threshold used in the analysis of Other Operating Revenue is the same one used throughout the entire 2010 rate application, $53,080 as calculated per the Filing Guidelines as 0.5% of distribution revenue requirement. The other operating revenue accounts exceeding the materiality threshold have been highlighted in earlier Table 2 and further explained in detail below.

Late Payment Charges Variance - 2006 Actual to 2006 Board Approved

Account	2006 Board Approved	2006 Actual	Variance
4225 Late Payment Charges	$ 153,625	$ 288,988	$ 135,363

Late payment charges in both the 2006 Board Approved (2004 Actual) and the 2006 Actual include both collection charges and late payment interest charged to the customer on account of customers failing to pay their electric bills on or before a specified date. This follows the definition as outlined in the OEB's *APH Article 220, Uniform System of Accounts* for account 4225. The variance in account 4225 is on account of the rate increase effective May 1, 2006 for the Collection Charge portion. Prior to May 1, 2006 the rate was $9.00 per charge and increased to $30.00 per charge as per the standard in the 2006 EDR Handbook and model guidelines.

Specific Service Charge Variance - 2006 Actual to 2006 Board Approved

Account	2006 Board Approved	2006 Actual	Variance
4225 Late Payment Charges	$ 379,469	$ 167,625	$(211,844)

This negative variance from the 2006 Board Approved (2004 Actual) to the 2006 Actual is on account of the same reason mentioned above in the Late Payment Charge variance explanation. HCHI codes Collection charges to account 4225 and

thus has included them in the Late Payment Charge line of Other Operating Revenue. In the 2006 EDR, the specific service charge amount includes collection charges in the amount of $199,440; that is, the majority of the variance.

Other Distribution Revenue Variance - 2006 Actual to 2006 Board Approved

Account	2006 Board Approved	2006 Actual	Variance
4090 Distribution Wheeling Service Rate – NPI	$ 74,493	$ 54,749	$ (19,744)
4375 Revenue from Non-Utility Operations	$ 0	$ 323,139	$ 323,139
4390 Miscellaneous Non-Operating Income	$ (5,299)	$ 109,625	$ 114,924
4405 Interest and Dividend Income	$ 29,929	$261,757	$231,828

The variance of $627,631 in Table 2 for Other Distribution Revenue from 2006 Board Approved to 2006 Actual is the combined net change in other distribution revenue accounts and other income and expense accounts. These accounts are detailed in the above table. The first factor is the difference in distribution wheeling service rate revenue actually charged to NPI in 2006 as compared to the amount calculated and included in the 2006 EDR. The 2006 EDR allowed for the calculation of this new rate in order to recover costs associated with the embedded distributor situation involving NPI. The rate was calculated on 12 months of costs and the associated revenue but not effective until May 1, 2006, therefore creating the negative variance between 2006 Board Approved and 2006 Actual of $(19,744). The second factor contributing to the overall variance is account 4375. This variance is caused by the exclusion of this account from the revenue offsets during the 2006 EDR process and treated as "Unclassified". As part of this 2010 rate application, HCHI has included this revenue as

forming part of the revenue offsets to our revenue requirement. The third factor is that account 4390 has shown a significant increase from the 2006 Board Approved (2004 Actual) to the 2006 Actual. The majority of this increase is due to the amount of distribution revenue collected on account of long-term load transfers ("LTLT's") for prior periods. In the Board Approved, the net charge to revenue represented the LTLT's settled with NPI only; a net due to NPI, and in 2006 Actual, the net revenue represented the LTLT's settled with NPI and HONI, a net owed to HCHI. The amount collected from HONI was approximately $93,000 greater than the amount owed to NPI. The balance of the variance is attributed to the increase in account 4405. In the Board Approved amount the interest recorded in 4405 on account of deferral and variance accounts was included. For purposes of the 2010 rate application, HCHI has removed the amount of interest attributed to deferral and variance accounts from account 4405 for 2006, 2007, and 2008 actual years and from the 2009 Bridge year and 2010 Test year. The result is an increase to the account balance as the deferral and variance account interest has historically been a charge against revenue versus an additional credit to revenue.

Other Distribution Revenue Variance - 2008 Actual to 2007 Actual

Account	2007 Actual	2008 Actual	Variance
4405 Interest and Dividend Income	$ 266,053	$ 151,971	$(114,082)

The negative variance from the 2007 actual year to the 2008 actual year is solely attributable to the interest earned on HCHI's bank accounts. The decline in revenue was caused by two factors; one, a decline in the prime rate and two, a decline in the average bank balance from 2007 to 2008. HCHI earns interest each month on a tiered structure based on the monthly average prime rate less a percentage for each tier. (2007 average prime 6.1% versus 2008 average prime 4.7%) HCHI's decline in the average bank balance was due to the funding of additional capital expenditures in 2008.

(2007 average bank balance of $6,492,408 versus 2008 average bank balance of $4,626,795).

Other Distribution Revenue Variance - 2009 Bridge to 2008 Actual

Account	2008 Actual	2009 Bridge	Variance
4090 Electric Services Incidental to Energy Sales	$ 136,928	$ 107,425	$ (29,503)
4355 Gain on Sale of Capital Assets	$ 16,530	$ 0	$ (16,530)
4390 Miscellaneous Non-Operating Income	$ 81,467	$ 63,140	$ (18,327)
4405 Interest and Dividend Income	$ 151,971	$ 67,548	$ (84,423)

The reduction in revenue from 2008 actual to the 2009 Bridge year is caused by a number of reasons. The first one relates to reduced distribution wheeling service rate revenue to be collected from NPI in 2009 due to the elimination of one supply point as discussed in this Exhibit at Tab 2, Schedule 1, Table 9. Secondly, in accounts 4355 and 4390, the decline in revenue represents items that HCHI is not forecasting to reoccur in the 2009 Bridge year as follows:

1. HCHI is not forecasting to receive any gain or loss on the disposal of assets in 2009; and
2. HCHI did not forecast revenue to reoccur in 2009 that represented one-time items in 2008, such as the ORST Refund, the proceeds on the closing of the partnership with EnerConnect, and the large payment received for recovery of court awarded costs.

The balance of the variance between 2008 actual and the 2009 bridge year is in account 4405. The interest earned on the bank account was forecast to be less in 2009

than 2008 actual based on the trend experienced in 2008 with the declining average bank prime rate. When the 2009 forecast was completed, there were 9 months of 2008 actual activity available to prepare the forecast; therefore, HCHI used the average bank balance from January to September 2008 to calculate the interest to be earned in 2009 at a forecasted average prime rate of 3%.

Other Distribution Revenue Variance - 2010 Test to 2009 Bridge

Account	2009 Bridge	2010 Test	Variance
4390 Miscellaneous Non-Operating Income	$ 63,140	$ 2,727	$ (60,413)

The decline in revenue from the 2009 Bridge year to the 2010 Test year is on account of LTLT's. HCHI's plan was to have all LTLT's eliminated by January 2009, as per the amendments to the DSC dated March 12, 2007, that was the requirement at the time of HCHI's budget (forecast) preparation. This resulted in no forecast miscellaneous revenue to be received on account of LTLT's.

Haldimand County Hydro

HALDIMAND COUNTY HYDRO INC.
1 Greendale Drive
Caledonia, ON
N3W 2J3
Tel: (905) 765-5344
Toll Free: (877) 872-2570
Fax: (905) 765-5316

December 30, 2008

Mr. Brad Randall
President & CEO
Norfolk Power Distribution Inc.
P.O. Box 588
70 Victoria Street
Simcoe ON N3Y 4N6

Dear Mr. Randall:

The Ontario Energy Board approved a "*Low Voltage Wheeling Rate*", associated Retail Transmission Rates, and a loss factor effective May 1, 2006 for Haldimand County Hydro to charge Norfolk Power for the following embedded supply points:

- Recorder 1000003570 – 57M4 at Concession 6 Woodhouse, and
- Recorder 1000003580 – 57M4 at Highway 6.

Subsequently, on December 12, 2008, Norfolk Power eliminated its need for supply from the 57M4 at Concession 6 Woodhouse in favour of supplying this load directly from its own 22M5 feeder with the intent to remove and deregister this metering equipment.

Haldimand County Hydro has been selected by the Ontario Energy Board for rate rebasing in 2010 and is actively preparing the necessary voluminous documentation for this rate application including load forecasts, cost allocation, etc. Consequently, we need to know the load forecast and future intentions of Norfolk Power with respect to the remaining embedded supply point on the 57M4 feeder at Highway 6. Accordingly, can you please provide the following information:

1. Does Norfolk Power intend to discontinue its embedded supply from the 57M4 feeder at Highway 6 within the next 5 years and, if so, please predict the approximate date?
2. If Norfolk Power intends to continue its embedded supply from the 57M4 feeder at Highway 6, can you please comment on and provide load forecast information for this supply point, including whether Norfolk Power has any information to suggest a significant increase or decrease in load may occur within the next 5 years. This information will be used in our application to the Ontario Energy Board for 2010 rates and associated losses.

We would appreciate the requested information at your earliest convenience since it is integral to our preparatory analysis.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Lloyd Payne
President & CEO

LP: nm

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JAN 0 9 2009

Norfolk Power
IN BUSINESS TO SERVE.

January 6, 2009

Haldimand County Hydro
1 Greendale Drive
Caledonia, ON N3W 2J3

Attn: Mr. Lloyd Payne
President & CEO

Re: Embedded Supply Projections via Jarvis TS 57M4 Feeder

Dear Lloyd,

In response to your letter of December 30, 2008, we are pleased to provide you the following information regarding our future supply requirements. For 2009, our approved capital budget includes a project to double the capacity of our Bloomsburg TS. Based on current installation projections, we should be able to discontinue our feed from Jarvis TS by the end of 2010.

The installation of our new transformer at Bloomsburg TS will coincide with the doubling of the 115kV A1N circuit which supplies much of Norfolk County. However, we will need to build a feeder extension into Port Dover before a load transition from Jarvis TS to Bloomsburg TS can occur. Some minor system re-configuration will also be necessary to facilitate a loop feed into the area.

Hopefully, this information will be helpful in preparation of your 2010 rate rebasing. Please do not hesitate to contact me if you have any other questions.

Sincerely,

Brad Randall, P.Eng.
President & CEO
Norfolk Power Inc.

pc: B. Pereira

P.O. Box 588 ~ 70 Victoria Street ~ Simcoe, Ontario ~ N3Y 4N6
Tel 519 426-4440 ~ Fax 519 426-6509 ~ 1-800-465-0291

APPENDIX B
Monthly Regression Analysis Data

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring / Fall Flag	Number of Customers (2000)	Population (1996)	Number of Peak Hours	Blackout Flag	Summer Months Flag	Predicted Purchases
							19,389	42,041				
Jan-01	33,597,449	703.0	0.0	119.2	31	0	19,422	43,391	352	0	0	33,058,728
Feb-01	29,121,821	597.3	0.0	119.4	28	0	19,455	43,419	320	0	0	29,199,702
Mar-01	30,151,932	598.5	0.0	119.6	31	1	19,488	43,447	352	0	0	29,822,702
Apr-01	26,013,183	314.1	0.0	119.8	30	1	19,521	43,475	320	0	0	26,116,719
May-01	25,929,175	142.2	8.3	119.9	31	1	19,554	43,503	352	0	0	26,220,301
Jun-01	29,845,050	40.9	63.7	120.1	30	0	19,587	43,531	336	0	1	29,197,558
Jul-01	30,934,008	17.9	79.6	120.3	31	0	19,620	43,559	336	0	1	31,310,412
Aug-01	33,262,022	0.7	114.0	120.4	31	0	19,653	43,587	352	0	1	33,783,096
Sep-01	26,978,767	93.3	21.8	120.6	30	1	19,686	43,615	304	0	0	26,619,771
Oct-01	27,725,045	243.5	0.0	120.8	31	1	19,719	43,643	352	0	0	27,984,596
Nov-01	28,474,729	332.1	0.0	121.0	30	1	19,752	43,671	352	0	0	28,159,045
Dec-01	33,080,498	535.2	0.0	121.1	31	0	19,784	**43,728**	304	0	0	34,022,734
Jan-02	33,542,938	592.6	0.0	121.5	31	0	19,797	43,753	352	0	0	34,669,642
Feb-02	31,368,997	553.9	0.0	121.9	28	0	19,810	43,778	320	0	0	31,230,077
Mar-02	31,370,348	539.3	0.0	122.2	31	1	19,823	43,803	320	0	0	31,376,113
Apr-02	27,935,139	338.9	8.0	122.6	30	1	19,836	43,828	352	0	0	28,905,046
May-02	28,437,763	248.9	8.3	122.9	31	1	19,849	43,853	352	0	0	28,984,425
Jun-02	30,244,841	41.9	64.7	123.3	30	0	19,862	43,878	320	0	1	30,650,138
Jul-02	36,899,343	0.9	151.0	123.7	31	0	19,875	43,903	352	0	1	37,200,286
Aug-02	35,023,534	4.2	94.4	124.0	31	0	19,888	43,928	336	0	1	33,302,888
Sep-02	30,176,849	32.8	61.3	124.4	30	1	19,901	43,953	320	0	0	29,324,282
Oct-02	27,929,423	304.1	8.9	124.8	31	1	19,914	43,978	352	0	0	29,533,868
Nov-02	30,012,930	449.5	0.0	125.1	30	1	19,927	44,003	336	0	0	29,385,971
Dec-02	34,947,762	643.2	0.0	125.5	31	0	19,938	44,028	320	0	0	34,994,193
Jan-03	36,662,669	829.5	0.0	125.7	31	0	19,945	44,053	352	0	0	36,929,367
Feb-03	32,216,878	699.2	0.0	125.8	28	0	19,952	44,078	320	0	0	32,532,797
Mar-03	32,592,426	593.1	0.0	126.0	31	1	19,959	44,103	336	0	0	31,746,003
Apr-03	28,484,458	387.1	0.0	126.1	30	1	19,966	44,128	336	0	0	28,606,720
May-03	27,549,364	215.8	0.0	126.2	31	1	19,973	44,153	336	0	0	27,815,333
Jun-03	28,594,490	54.5	41.4	126.4	30	0	19,979	44,178	336	0	1	28,937,405
Jul-03	33,152,864	6.5	83.9	126.5	31	0	20,002	44,203	352	0	1	32,546,758
Aug-03	33,546,964	5.7	102.6	126.7	31	0	20,043	44,228	320	1	1	33,546,964
Sep-03	28,300,069	73.9	14.8	126.8	30	1	20,073	44,253	336	0	0	27,107,451
Oct-03	29,570,748	293.5	0.0	127.0	31	1	20,085	44,278	352	0	0	29,395,795
Nov-03	30,816,096	391.5	0.0	127.1	30	1	20,108	44,303	320	0	0	29,521,597
Dec-03	35,841,514	571.0	0.0	127.3	31	0	20,110	44,328	336	0	0	34,982,527

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring / Fall Flag	Number of Customers	Population	Number of Peak Hours	Blackout Flag	Summer Months Flag	Predicted Purchases
Jan-04	38,418,884	859.1	0.0	127.5	31	0	20,115	44,353	336	0	0	37,867,098
Feb-04	33,440,258	647.7	0.0	127.8	29	0	20,131	44,378	320	0	0	33,728,484
Mar-04	32,352,926	513.6	0.0	128.1	31	1	20,153	44,403	368	0	0	31,845,870
Apr-04	28,034,857	329.3	0.0	128.3	30	1	20,163	44,428	336	0	0	28,889,688
May-04	28,679,952	164.1	14.2	128.6	31	1	20,182	44,453	320	0	0	29,224,363
Jun-04	28,777,312	60.1	29.2	128.9	30	0	20,203	44,478	352	0	1	29,305,717
Jul-04	32,245,498	7.7	71.6	129.1	31	0	20,242	44,503	336	0	1	32,973,231
Aug-04	31,231,984	28.9	40.0	129.4	31	0	20,248	44,528	336	0	1	30,947,849
Sep-04	29,977,471	43.9	31.2	129.7	30	1	20,277	44,553	336	0	0	28,735,754
Oct-04	30,210,596	253.5	0.0	129.9	31	1	20,285	44,578	320	0	0	29,670,631
Nov-04	31,443,174	396.0	0.0	130.2	30	1	20,304	44,603	352	0	0	30,267,577
Dec-04	37,443,528	636.7	0.0	130.5	31	0	20,308	44,628	336	0	0	36,304,917
Jan-05	38,588,370	765.8	0.0	130.7	31	0	20,314	44,653	320	0	0	37,536,083
Feb-05	32,788,470	641.7	0.0	131.0	28	0	20,314	44,678	320	0	0	33,130,660
Mar-05	33,560,529	646.9	0.0	131.3	31	1	20,353	44,703	352	0	0	33,842,326
Apr-05	28,067,410	339.0	0.0	131.6	30	1	20,364	44,728	336	0	0	29,642,512
May-05	28,033,376	212.7	0.0	131.9	31	1	20,384	44,753	336	0	0	29,426,663
Jun-05	34,051,463	13.1	119.6	132.2	30	0	20,410	44,778	352	0	1	35,755,433
Jul-05	38,068,287	1.1	144.7	132.5	31	0	20,419	44,803	320	0	1	38,271,092
Aug-05	35,835,110	3.8	102.5	132.8	31	0	20,436	44,828	352	0	1	35,489,935
Sep-05	30,006,887	32.8	25.6	133.1	30	1	20,444	44,853	336	0	0	28,461,102
Oct-05	29,588,399	234.2	7.6	133.4	31	1	20,454	44,878	320	0	0	30,236,408
Nov-05	31,614,193	396.3	0.0	133.7	30	1	20,457	44,903	352	0	0	30,319,785
Dec-05	37,747,216	688.8	0.0	134.0	31	0	20,465	44,928	320	0	0	36,905,639
Jan-06	35,087,685	554.7	0.0	134.3	31	0	20,484	44,953	336	0	0	35,629,609
Feb-06	32,387,946	602.8	0.0	134.5	28	0	20,484	44,978	320	0	0	32,975,537
Mar-06	32,659,459	530.4	0.0	134.8	31	1	20,484	45,003	368	0	0	32,466,128
Apr-06	26,787,901	314.6	0.0	135.1	30	1	20,485	45,028	304	0	0	29,033,389
May-06	27,503,587	155.5	22.4	135.4	31	1	20,493	45,053	352	0	0	29,955,277
Jun-06	29,952,375	26.7	43.2	135.6	30	0	20,493	45,078	352	0	1	29,890,577
Jul-06	36,277,085	1.9	136.1	135.9	31	0	20,493	45,103	320	0	1	36,843,318
Aug-06	33,329,530	8.1	70.1	136.2	31	0	20,507	45,128	352	0	1	32,428,339
Sep-06	28,064,773	105.3	4.1	136.5	30	1	20,551	45,153	320	0	0	27,246,932
Oct-06	30,233,031	304.1	0.0	136.8	31	1	20,563	45,178	336	0	0	30,025,559
Nov-06	31,587,658	393.1	0.0	137.0	30	1	20,575	45,203	352	0	0	29,965,181
Dec-06	34,663,730	508.1	0.0	137.3	31	0	20,581	**45,212**	304	0	0	34,728,919
Jan-07	35,889,158	665.6	0.0	137.6	31	0	20,581	45,245	352	0	0	36,260,709
Feb-07	34,017,544	761.8	0.0	137.8	28	0	20,581	45,278	320	0	0	34,064,023
Mar-07	32,604,794	565.2	0.0	138.1	31	1	20,581	45,311	352	0	0	32,239,249
Apr-07	28,644,659	374.2	0.0	138.3	30	1	20,581	45,344	320	0	0	29,079,813
May-07	27,938,156	138.4	23.3	138.6	31	1	20,595	45,377	352	0	0	29,306,719
Jun-07	32,019,209	19.2	74.2	138.8	30	0	20,617	45,410	336	0	1	31,629,692

		Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring / Fall Flag	Number of Customers	Population	Number of Peak Hours	Blackout Flag	Summer Months Flag	Predicted Purchases
Jul-07		32,377,216	9.2	82.0	139.1	31	0	20,636	45,443	336	0	1	33,123,464
Aug-07		35,026,642	8.4	106.0	139.3	31	0	20,639	45,476	352	0	1	34,669,133
Sep-07		29,896,811	55.2	37.2	139.6	30	1	20,655	45,509	304	0	0	28,416,537
Oct-07		29,518,757	157.8	13.0	139.8	31	1	20,666	45,542	352	0	0	28,839,263
Nov-07		30,921,288	467.5	0.0	140.1	30	1	20,691	45,575	352	0	0	30,266,037
Dec-07		36,272,681	641.0	0.0	140.3	31	0	20,702	45,608	304	0	0	35,629,651
Jan-08		35,810,334	633.6	0.0	140.3	31	0	20,713	45,641	352	0	0	35,667,731
Feb-08		32,883,861	678.8	0.0	140.3	29	0	20,714	45,674	320	0	0	34,028,803
Mar-08		31,938,647	620.7	0.0	140.2	31	1	20,722	45,707	304	0	0	32,732,890
Apr-08		28,132,254	288.1	0.0	140.2	30	1	20,728	45,740	352	0	0	28,374,246
May-08		27,152,520	214.1	0.3	140.1	31	1	20,729	45,773	336	0	0	28,539,133
Jun-08		30,002,892	34.2	55.0	140.1	30	0	20,738	45,806	336	0	1	30,447,231
Jul-08		34,123,826	3.7	87.7	140.0	31	0	20,760	45,839	352	0	1	33,577,439
Aug-08		31,806,390	20.2	45.2	140.0	31	0	20,769	45,872	320	0	1	30,799,977
Sep-08		28,611,094	70.5	19.8	139.9	30	1	20,787	45,905	336	0	0	27,760,618
Oct-08		28,851,748	297.5	0.0	139.9	31	1	20,793	45,938	352	0	0	29,738,967
Nov-08		30,694,201	460.6	0.0	139.8	30	1	20,820	45,971	304	0	0	30,585,191
Dec-08		36,473,843	655.3	0.0	139.8	31	0	20,819	46,004	336	0	0	36,216,399
Jan-08	WN	35,810,334	700.5	0.0	140.3	31	0	20,713	45,641	352	0	0	36,355,527
Feb-08	WN	32,883,861	647.9	0.0	140.3	29	0	20,714	45,674	320	0	0	33,711,063
Mar-08	WN	31,938,647	576.0	0.0	140.2	31	1	20,722	45,707	304	0	0	32,272,860
Apr-08	WN	28,132,254	335.7	1.0	140.2	30	1	20,728	45,740	352	0	0	28,932,186
May-08	WN	27,152,520	186.5	9.6	140.1	31	1	20,729	45,773	336	0	0	28,895,352
Jun-08	WN	30,002,892	36.3	61.4	140.1	30	0	20,738	45,806	336	0	1	30,908,074
Jul-08	WN	34,123,826	6.1	104.6	140.0	31	0	20,760	45,839	352	0	1	34,764,283
Aug-08	WN	31,806,390	10.0	84.4	140.0	31	0	20,769	45,872	320	0	1	33,391,016
Sep-08	WN	28,611,094	63.5	27.0	139.9	30	1	20,787	45,905	336	0	0	28,182,333
Oct-08	WN	28,851,748	261.0	3.7	139.9	31	1	20,793	45,938	352	0	0	29,617,826
Nov-08	WN	30,694,201	410.8	0.0	139.8	30	1	20,820	45,971	304	0	0	30,073,362
Dec-08	WN	36,473,843	609.9	0.0	139.8	31	0	20,819	46,004	336	0	0	35,749,685
Jan-09													34,901,306
Feb-09													32,362,620
Mar-09													30,981,946
Apr-09													27,774,899
May-09													27,739,538
Jun-09													29,671,751
Jul-09													33,373,712
Aug-09													32,055,376
Sep-09													27,055,040
Oct-09													28,433,112
Nov-09													28,870,427
Dec-09													34,319,698

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring / Fall Flag	Number of Customers	Population	Number of Peak Hours	Blackout Flag	Summer Months Flag	Predicted Purchases
Jan-10												34,796,602
Feb-10												32,265,532
Mar-10												30,889,000
Apr-10												27,691,574
May-10												27,656,319
Jun-10												29,582,735
Jul-10												33,273,590
Aug-10												31,959,210
Sep-10												26,973,874
Oct-10												28,347,813
Nov-10												28,783,816
Dec-10												34,216,738
							0	**47,212**				
								(2011)				4,147,511,299
2001	355,113,677											355,495,365
2002	377,889,868											379,556,929
2003	377,328,535											373,668,716
2004	382,256,439											379,761,179
2005	397,949,707											399,017,639
2006	378,534,757											381,188,764
2007	385,126,910											383,524,291
2008	376,481,614											378,468,624
2008 WN												382,853,565
2009										-2.9%	-4.0%	367,539,422
2010										-3.2%	-0.3%	366,436,804
Total to 2008	3,030,681,507											3,030,681,507
												4,147,511,299

APPENDIX C
Monthly Heating & Cooling Degree Days

8-Year Average (2001 to 2008)

8 Year Average of Heating Degree Days

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2001	703.0	597.3	598.5	314.1	142.2	40.9	17.9	0.7	93.3	243.5	332.1	535.2	3,618.7
2002	592.6	553.9	539.3	338.9	248.9	41.9	0.9	4.2	32.8	304.1	449.5	643.2	3,750.2
2003	829.5	699.2	593.1	387.1	215.8	54.5	6.5	5.7	73.9	293.5	391.5	571.0	4,121.3
2004	859.1	647.7	513.6	329.3	164.1	60.1	7.7	28.9	43.9	253.5	396.0	636.7	3,940.6
2005	765.8	641.7	646.9	339.0	212.7	13.1	1.1	3.8	32.8	234.2	396.3	688.8	3,976.2
2006	554.7	602.8	530.4	314.6	155.5	26.7	1.9	8.1	105.3	304.1	393.1	508.1	3,505.3
2007	665.6	761.8	565.2	374.2	138.4	19.2	9.2	8.4	55.2	157.8	467.5	641.0	3,863.5
2008	633.6	678.8	620.7	288.1	214.1	34.2	3.7	20.2	70.5	297.5	460.6	655.3	3,977.3
Average	700.5	647.9	576.0	335.7	186.5	36.3	6.1	10.0	63.5	261.0	410.8	609.9	

8 Year Average of Cooling Degree Days

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2001	-	-	-	-	8.3	63.7	79.6	114.0	21.8	-	-	-	287.4
2002	-	-	-	8.0	8.3	64.7	151.0	94.4	61.3	8.9	-	-	396.6
2003	-	-	-	-	-	41.4	83.9	102.6	14.8	-	-	-	242.7
2004	-	-	-	-	14.2	29.2	71.6	40.0	31.2	-	-	-	186.2
2005	-	-	-	-	-	119.6	144.7	102.5	25.6	7.6	-	-	400.0
2006	-	-	-	-	22.4	43.2	136.1	70.1	4.1	-	-	-	275.9
2007	-	-	-	-	23.3	74.2	82.0	106.0	37.2	13.0	-	-	335.7
2008	-	-	-	-	0.3	55.0	87.7	45.2	19.8	-	-	-	208.0
Average	-	-	-	1.0	9.6	61.4	104.6	84.4	27.0	3.7	-	-	

10-Year Average (1999 to 2008)

10 Year Average of Heating Degree Days

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1999	774.6	556.8	566.8	317.5	113.1	37.5	1.0	12.7	71.0	282.5	377.2	588.5	3,699.2
2000	747.9	622.7	434.7	363.5	151.7	42.8	12.2	18.0	115.3	230.8	447.4	811.6	3,998.6
2001	703.0	597.3	598.5	314.1	142.2	40.9	17.9	0.7	93.3	243.5	332.1	535.2	3,618.7
2002	592.6	553.9	539.3	338.9	248.9	41.9	0.9	4.2	32.8	304.1	449.5	643.2	3,750.2
2003	829.5	699.2	593.1	387.1	215.8	54.5	6.5	5.7	73.9	293.5	391.5	571.0	4,121.3
2004	859.1	647.7	513.6	329.3	164.1	60.1	7.7	28.9	43.9	253.5	396.0	636.7	3,940.6
2005	765.8	641.7	646.9	339.0	212.7	13.1	1.1	3.8	32.8	234.2	396.3	688.8	3,976.2
2006	554.7	602.8	530.4	314.6	155.5	26.7	1.9	8.1	105.3	304.1	393.1	508.1	3,505.3
2007	665.6	761.8	565.2	374.2	138.4	19.2	9.2	8.4	55.2	157.8	467.5	641.0	3,863.5
2008	633.6	678.8	620.7	288.1	214.1	34.2	3.7	20.2	70.5	297.5	460.6	655.3	3,977.3
Average	712.6	636.3	560.9	336.6	175.7	37.1	6.2	11.1	69.4	260.2	411.1	627.9	

10 Year Average of Cooling Degree Days

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1999	-	-	-	-	13.6	86.3	163.7	47.0	38.5	-	-	-	349.1
2000	-	-	-	-	18.7	38.6	57.7	58.3	30.1	0.2	-	-	203.6
2001	-	-	-	-	8.3	63.7	79.6	114.0	21.8	-	-	-	287.4
2002	-	-	-	8.0	8.3	64.7	151.0	94.4	61.3	8.9	-	-	396.6
2003	-	-	-	-	-	41.4	83.9	102.6	14.8	-	-	-	242.7
2004	-	-	-	-	14.2	29.2	71.6	40.0	31.2	-	-	-	186.2
2005	-	-	-	-	-	119.6	144.7	102.5	25.6	7.6	-	-	400.0
2006	-	-	-	-	22.4	43.2	136.1	70.1	4.1	-	-	-	275.9
2007	-	-	-	-	23.3	74.2	82.0	106.0	37.2	13.0	-	-	335.7
2008	-	-	-	-	0.3	55.0	87.7	45.2	19.8	-	-	-	208.0
Average	-	-	-	0.8	10.9	61.6	105.8	78.0	28.4	3.0	-	-	

20-Year Trend (1989 to 2008)

20 Year Trend of Heating Degree Days

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1989	628.4	687.2	594.7	392.1	181.0	44.4	3.3	19.7	98.4	256.1	475.4	855.2	4,235.9
1990	587.2	593.6	523.7	304.7	210.4	39.5	4.8	8.2	103.2	280.7	407.5	586.4	3,649.9
1991	744.0	565.4	509.9	296.8	110.2	17.0	4.0	6.6	122.7	243.7	468.5	615.2	3,704.0
1992	680.4	629.6	593.7	394.6	178.2	76.7	31.6	47.6	118.5	327.2	456.8	618.6	4,153.5
1993	672.3	729.1	640.8	355.3	186.0	54.3	1.7	8.6	148.1	321.9	449.7	624.2	4,192.0
1994	920.4	747.1	595.8	333.9	212.6	42.8	3.6	29.0	91.9	251.4	375.0	569.6	4,173.1
1995	643.1	709.5	499.0	422.7	165.4	21.7	13.4	4.1	121.0	223.7	516.7	713.3	4,053.6
1996	774.2	699.4	666.6	408.3	210.1	26.5	12.0	2.2	85.4	272.4	521.0	570.8	4,248.9
1997	746.1	573.8	583.1	375.1	269.6	33.3	14.5	23.1	89.5	270.0	485.1	596.9	4,060.1
1998	620.8	520.3	504.6	290.7	82.1	63.3	1.3	5.3	51.8	234.9	402.7	539.5	3,317.3
1999	774.6	556.8	566.8	317.5	113.1	37.5	1.0	12.7	71.0	282.5	377.2	588.5	3,699.2
2000	747.9	622.7	434.7	363.5	151.7	42.8	12.2	18.0	115.3	230.8	447.4	811.6	3,998.6
2001	703.0	597.3	598.5	314.1	142.2	40.9	17.9	0.7	93.3	243.5	332.1	535.2	3,618.7
2002	592.6	553.9	539.3	338.9	248.9	41.9	0.9	4.2	32.8	304.1	449.5	643.2	3,750.2
2003	829.5	699.2	593.1	387.1	215.8	54.5	6.5	5.7	73.9	293.5	391.5	571.0	4,121.3
2004	859.1	647.7	513.6	329.3	164.1	60.1	7.7	28.9	43.9	253.5	396.0	636.7	3,940.6
2005	765.8	641.7	646.9	339.0	212.7	13.1	1.1	3.8	32.8	234.2	396.3	688.8	3,976.2
2006	554.7	602.8	530.4	314.6	155.5	26.7	1.9	8.1	105.3	304.1	393.1	508.1	3,505.3
2007	665.6	761.8	565.2	374.2	138.4	19.2	9.2	8.4	55.2	157.8	467.5	641.0	3,863.5
2008	633.6	678.8	620.7	288.1	214.1	34.2	3.7	20.2	70.5	297.5	460.6	655.3	3,977.3
Trend	704.4	636.1	563.7	362.2	176.4	45.5	9.9	17.1	118.4	275.8	456.2	652.7	

20 Year Trend of Cooling Degree Days

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1989	-	-	-	-	10.3	39.8	104.3	62.8	26.0	-	-	-	243.2
1990	-	-	-	16.9	0.7	42.8	81.4	66.1	15.7	3.2	-	-	226.8
1991	-	-	-	1.5	52.5	64.3	85.6	74.1	33.5	2.2	-	-	313.7
1992	-	-	-	-	4.3	12.2	24.2	28.2	19.7	-	-	-	88.6
1993	-	-	-	-	2.9	28.7	111.4	101.1	12.3	0.7	-	-	257.1
1994	-	-	-	-	7.5	66.5	95.0	43.2	10.6	-	-	-	222.8
1995	-	-	-	-	0.6	75.3	124.9	123.9	12.9	0.2	-	-	337.8
1996	-	-	-	-	10.7	32.7	56.3	78.1	22.5	-	-	-	200.3
1997	-	-	-	-	-	61.8	72.1	37.2	6.7	3.9	-	-	181.7
1998	-	-	-	-	29.2	79.2	74.0	100.7	41.4	-	-	-	324.5
1999	-	-	-	-	13.6	86.3	163.7	47.0	38.5	-	-	-	349.1
2000	-	-	-	-	18.7	38.6	57.7	58.3	30.1	0.2	-	-	203.6
2001	-	-	-	-	8.3	63.7	79.6	114.0	21.8	-	-	-	287.4
2002	-	-	-	8.0	8.3	64.7	151.0	94.4	61.3	8.9	-	-	396.6
2003	-	-	-	-	-	41.4	83.9	102.6	14.8	-	-	-	242.7
2004	-	-	-	-	14.2	29.2	71.6	40.0	31.2	-	-	-	186.2
2005	-	-	-	-	-	119.6	144.7	102.5	25.6	7.6	-	-	400.0
2006	-	-	-	-	22.4	43.2	136.1	70.1	4.1	-	-	-	275.9
2007	-	-	-	-	23.3	74.2	82.0	106.0	37.2	13.0	-	-	335.7
2008	-	-	-	-	0.3	55.0	87.7	45.2	19.8	-	-	-	208.0
Trend	-	-	-	3.1	12.6	43.8	81.3	67.0	20.5	0.0	-	-	

Exhibit	Tab	Schedule	Appendix	Contents
4 – Operating Costs				
	1			**Overview**
		1		Overview of Operating Costs
	2			**OM&A Costs**
		1		Departmental and Corporate OM&A Activities
		2		OM&A Detailed Costs Table
		3		Variance Analysis on OM&A Costs
		4		OM&A Specific Requirements
		5		Charges to / from Affiliates for Services Provided
		6		Purchase of Non-Affiliate Services
		7		Employee Complement, Benefits, and Compensation
		8		Amortization of Capital Assets
	3			**Taxes (PILs, Capital Tax and Property Taxes)**
		1		Detailed PILS/Tax Calculations
			A	Federal T2 Corporation Income Tax Return and Ontario CT23 Corporations Tax and Annual Return
		2		Property Taxes

OVERVIEW OF OPERATING COSTS

Operating Costs

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Haldimand County Hydro Inc.'s ("HCHI") distribution operations. HCHI follows the OEB's Accounting Procedures Handbook ("APH") in distinguishing work performed between operations and maintenance. A summary of HCHI's operating, maintenance, and administrative costs for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and the 2010 Test Year is provided in Table 1 below with percentage changes identified. Table 2 represents the OM&A cost per customer and per full-time equivalent employee.

Table 1
Summary of OM&A Expenses

Description	2006 Board Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Bridge	Variance	2010 Test	Variance
OM&A expenses											
Operation	937,061	1,158,902	221,841	1,193,191	34,289	1,222,063	28,872	1,386,280	164,217	1,437,648	51,368
Maintenance	1,697,968	1,430,796	(267,172)	2,856,418	1,425,622	2,660,402	(196,016)	2,767,244	106,842	2,802,733	35,489
Billing and Collections	1,096,342	1,246,221	149,879	1,278,655	32,434	1,303,979	25,324	1,355,335	51,356	1,403,423	48,088
Community Relations	28,035	85,931	57,896	123,846	37,915	38,719	(85,127)	45,972	7,253	46,836	864
Administrative and General Expenses	1,688,118	1,606,856	(81,262)	1,657,712	50,856	1,811,769	154,057	1,890,001	78,232	1,961,330	71,328
Total OM&A Expense (Controllables)	5,447,524	5,528,706		7,109,822		7,036,932		7,444,832		7,651,970	
Variance from Previous Year			81,182		1,581,116		(72,890)		407,900		207,138
Percent Change (year over year)			1.49%		28.60%		-1.03%		5.80%		2.78%
Percent Change Test Year versus 2008 Actual											8.74%
Percent Change Test Year versus 2006 Board Approved											40.47%
Average for 2007 and 2008 Actual											13.79%
Compound Annual Growth Rate for 2006, 2007, and 2008 Actual											12.82%

Table 2
OM&A Cost per Customer and FTEE

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Number of Customers (includes connections)	23,816	24,033	24,160	24,343	24,463	24,586
Total OM&A Expense (Controllables)	5,447,524	5,528,706	7,109,822	7,036,932	7,444,832	7,651,970
OM&A cost per Customer	228.73	230.05	294.28	289.07	304.33	311.23
Number of FTEEs	49	52	54	54	54	54
FTEEs / Customer	0.0021	0.0022	0.0022	0.0022	0.0022	0.0022
OM&A cost per FTEE	111,174	106,321	131,663	130,314	137,867	141,703

The OEB's *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, dated May 27, 2009 (the "Filing Guidelines") suggest a default materiality threshold for rate base, capital expenditures, OM&A and other items, and that it be determined based on a distributor's revenue requirement. HCHI's distribution revenue requirement falls into the category of greater than $10 million and less than or equal to $200 million; resulting in HCHI's materiality threshold calculated as 0.5% of the distribution revenue requirement. The calculation for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge, and 2010 Test are summarized in Table 3 below.

Table 3
OM&A Materiality

Description	2006 OEB Approved	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Distribution Revenue Requirement	$11,714,407	$10,616,006	$11,750,648	$11,546,990	$11,299,009	$12,919,004
Variance Calculation - 0.5% of above	$58,572	$53,080	$58,753	$57,735	$56,495	$64,595

HCHI has adopted a variance analysis threshold of $53,080 being the lowest of the variances amongst the years under review.

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided at Exhibit 4, Tab 2, Schedule 2.

OM&A Costs

OM&A costs in this Exhibit represent HCHI's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives, to comply with the *Distribution System Code* ("DSC"), 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 HCHI's distribution system, and meeting the requirements of the OEB's *Standard Supply Service Code* ("SSS") and *Retail Settlement Code* ("RSC").

The proposed OM&A cost expenditures for the 2010 Test Year are the result of business planning and work prioritization processes that ensure that the most appropriate, cost effective solutions are put into place.

HCHI is proposing recovery of 2010 Test Year OM&A costs, including amortization and taxes other than income taxes, totaling $10,637,504.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

HCHI is proposing recovery of 2010 Test Year taxes totaling $741,703 as calculated using the OEB's tax methodology provided in their tax model. Details of this amount are shown in Exhibit 4, Tab 3, Schedule 1.

OM&A Budgeting Process Used by Haldimand County Hydro Inc

The operating budget is prepared annually by Management and is reviewed and approved by the Board of Directors of HCHI. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work plans

Each Department Manager provides input for the preparation of the departmental budget. The following directives are provided to each Manager:

- Expenses for all department budgets are built using previous year actual, current year budget and current year forecast as the base;
- Review operating priorities and requirements to identify resources, including labour, trucks, materials and other third party costs that are required to complete budgeted item;
- Significant variances in spending from prior years must be explained and documented;
- Review the staff complement of department for accuracy and forecast any changes as a result of future requirements;
- Balance labour hours distributed to various accounts to total labour hours by employee within department;
- Overtime and account distribution are based on previous years actual, current year budget and current year forecast for all departments except Operations;
- Operations use a trending function (statistical function) method to estimate labour and truck hours allocated to accounts. This method uses actual data from 2003 to 2008 and trended values for 2009 and calculated values based on a linear trend line which best fits the known data; and
- Accounting prepares a worksheet of hourly labour rates including payroll burden by job classification using projected wage and benefit costs.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

HCHI 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*. A detailed explanation of the tax calculation is provided later in this Exhibit in Tab 3. A copy of the 2008 Federal T2 Corporation Income Tax Return and Ontario CT23 Corporations Tax and Annual Return has been provided in this Exhibit as Appendix A. Income Tax amounts included in the 2008 financial statements are based on estimates and will differ from the actual tax return. The difference between actual and estimate will be recorded in 2009 financial statements.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of the HCHI distribution system. This includes both direct and indirect labor costs, rolling stock, building and maintenance overheads and non-capital material spending to support both scheduled and reactive maintenance events.

HCHI'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).

HCHI's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with HCHI's capital project work, so that where maintenance programs have identified matters the correction of which require capital investments, HCHI may adjust its capital spending priorities to address those matters.

Predictive Maintenance

Predictive maintenance activities involve the testing of elements of the HCHI distribution system. These activities include infrared thermography testing, substation transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance

Preventative maintenance activities include annual tree and line clearing activities, inspection, servicing and repair of network components. This includes substation maintenance, overhead and pad-mounted load break switch maintenance, hydraulic recloser maintenance, and regulator maintenance. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, defective equipment, emergency tree trimming and on-call premiums. HCHI constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance.

Service Work

The majority of costs related to this work pertain to service upgrades requested by customers. This includes service disconnections and reconnections by HCHI for all service classes, assisting pre-approved contractors, the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades, and changes of service locations.

Network Control Operations

Network operating costs are related to the 24-hour monitoring of customer emergency calls. An answering service company has been contracted to contact an "on call" lineperson and supervisory staff in the event of service problems after normal business hours. The Line Department continuously monitors the system

and dispatch repair crews to manage equipment failures and provide work protection for the crews doing work on the system.

Metering

The Metering group, part of the Engineering Department, is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

The Engineering Department also provides underground locate service through the use of a third party contractor to anyone requesting verification of underground cable locations.

Substation Services

Substation services activities address the maintenance of all equipment at HCHI's 6 energized substations and 1 regulating transformer station. HCHI has 1 decommissioned substation to be dismantled in a future year. Service activities on the commissioned stations include both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. To a large extent, costs for substation service activities are provided by third party contractors specializing in this type of work. As with other maintenance activities, HCHI's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of HCHI's planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

Engineering is responsible for keeping asset related data up to date on an electronic Geographical Information System ("GIS"). The ESRI GIS system is a work in progress. Plans include integration with HCHI's Customer Information System ("CIS") to gather loading information for further understanding of our distribution system. This system will be used for asset management activities, identifying and correcting system problems, supplying underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. The GIS Technician also delivers drafting services to the Engineering Technicians for the design of capital projects and provides distribution system asset information to other departments within HCHI.

STORES/WAREHOUSE

Stores staff is accountable for managing the replenishment, control, and movement of materials within HCHI's service centre. This would include monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departments and capital as an overhead cost based on direct labour costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

GARAGE/TRANSPORTATION FLEET

The Operations and Engineering Departments support the inspection and maintenance and control of 17 fleet vehicles, 8 large trucks (i.e. buckets) and 7 small vehicles (i.e. pickups / vans). The objectives include maintenance of vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to all departments and capital based on number of hours used. A standard cost per hour is set for all vehicles within the fleet – one rate for large

trucks and one rate for small vehicles. Costs are adjusted to actual at year end and the hourly rates are reviewed annually for the following fiscal year.

SERVICE CENTRE

Costs collected in this area are for the operation and maintenance of the service centre, such as repairs to the service centre, landscape maintenance, building maintenance supplies, and security monitoring. Costs are allocated to all departments and capital as an overhead cost based on direct labour hours. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

LABOUR BURDEN / SAFETY AND HEALTH

The cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances are allocated to all departments and capital based on direct labour hours. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

In addition, the cost of Health and Safety is included in this burden allocation. Costs include Health and Safety program supplies and fees, and outside service costs associated with safety meetings. HCHI is committed to maximizing productivity and reducing risk of injury by initiating health and safety measures that focus on proactive actions. The commitment to health and safety is significant, and involves documenting meeting content and unsafe behaviors, safety training, monitoring conformance to established standards and policies, determining the effectiveness of safety training, implementation of a Risk Analysis Program, and monitoring the resolution of safety recommendations / audits, a commitment to continuous improvement in health and safety, and identifying and correcting root causes for system deficiencies. HCHI is a participant in E&USA's ZeroQuest program and has achieved the first step in the ZeroQuest program, the Bronze or Commitment Level.

CUSTOMER SERVICE

The Customer Service Department is responsible for the customer care activities for approximately 20,840 customers and two Embedded Distributors in HCHI's service territory, as at June 30, 2009. These activities include meter reading, billing, call centre, collections, and other back office functions. HCHI aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are accumulated in accounts 5305 to 5515.

Meter Reading

Meter reading services are contracted out to a non-affiliated third party under a service contract agreement. The contractor reads approximately 20,760 (as at June 30, 2009) electric service meters per month on average. The meter contract was awarded in January 2009 and signed for an initial term of two years from March 19, 2009 to March 19, 2011. In addition, the agreement will automatically renew annually at the end of the initial term or until such time that either party terminates the agreement upon 90 days written notice. HCHI is targeting full deployment of its smart meters by December 31, 2009 – as further detailed in Exhibit 9, Tab 2. During the process of the smart meter roll-out HCHI will be utilizing this same non-affiliated third party contractor to manually read the smart meter. Once the operational data store ("ODS") is fully operational and integrated it is expected that HCHI will be able to utilize the readings through the automated metering infrastructure ("AMI") network for meter reads.

Billing

HCHI operates on a monthly billing schedule, rendering approximately 252,900 invoices annually to customers. This total includes 2,700 final bills on average for customers moving within or outside of HCHI's service territory. An annual billing

schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes, EBT and retailer settlement functions for 2,945 retailer accounts, account adjustments, processing meter changes, and other various account related field service orders and mailing services. HCHI offers customers a number of payment options including an equal payment plan, electronic payment, and a preauthorized payment plan.

Collections

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. Credit risk is a concern for HCHI with 2010 credit loss forecast at $30,000 which is based on HCHI's historical write-off of uncollectible accounts. Consistent with prior years, HCHI attempts to maintain the allowance for doubtful accounts equal to the amount of aged arrears 90 days and older. In an effort to minimize credit losses, HCHI enforces a prudent credit policy in accordance with the DSC. Active overdue accounts are collected by in-house staff through notices and direct telephone contact. Final bill collections are also collected by in-house staff through notices and direct telephone contact. Final accounts that remain unpaid 30 days after the final due date are turned over to a collection agency.

Customer Contact

The Customer Service Department is also responsible for such activities as payment processing, move in and out requests, and call centre. On average call volumes continue to increase annually. HCHI's Customer Service staff handles over 39,000 inquiries per year. With the eventual roll-out of smart meter installations and time-of-use billing, HCHI anticipates an increase in call volume activity.

Community Relations

HCHI is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. HCHI staff is available to answer customer questions in a friendly environment.

Since LDCs are the "face-to-the-customer" for the electricity industry, HCHI has an important role to play in educating the public about electricity safety and energy conservation.

Education – Electricity Safety

HCHI supports elementary schools in Haldimand County by providing Electricity Safety and Conservation sessions for students in two age groups – JK to grade four and grades five to eight. These highly interactive sessions educate children in the dangers of electricity. HCHI also uses the internet to promote Electrical Safety and Energy Conservation to families by way of a conservation website; www.conserverjoe.com cooperatively with the NEPA (Niagara Erie Power Alliance) group of utilities.

Education – Energy Conservation

Building an energy conservation culture in Haldimand County continues to be an important objective for HCHI. HCHI is very active in the community promoting energy conservation initiatives, attending a number of community events each year, distributing compact florescent light bulbs and energy conservation handbooks. HCHI continues to participate with the Ontario Power Authority ("OPA") in promoting and administering programs directed at energy conservation.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within HCHI, 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:

- Board of Directors (i.e. Executive) (5605);
- Management (5610);
- Administrative, Finance and Regulatory Services (5615);
- Information Technology Services (5615);

Board of Directors (Executive) Salaries and Expenses: 5605

The Board of Directors oversees and approves the operational plans for the organization. Expenses include salaries and all related expenses associated with the Board of Directors for HCHI.

Management Salaries and Expenses: 5610

The President & Chief Executive Officer is responsible for all aspects of HCHI. Also included in this category are the other Department Managers, including Consumer Services, Engineering, Finance and Operations. Expenses include salaries and all related expenses for the employees within the above noted job classifications.

Administrative, Finance, and Regulatory Salaries and Expenses: 5615

- **Administrative Services**

Included in this category is the Executive Assistant to the President & CEO who also provides support to other Department Managers and to the Board of Directors. Expenses include salary and all related expenses for this individual.

- **Financial Services**

The Finance Department is responsible for the preparation of Government statutory, Management and Board of Directors financial reporting in accordance with GAAP, all daily accounting functions, including accounts payable, accounts receivable, 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. Expenses include salaries and all related expenses associated with the Accounting Supervisor, two Accountants, and the Accounting Clerk.

- **Regulatory Services**

The Regulatory Services are performed within the Finance Department by the Finance Manager with assistance from the Accounting Supervisor. They are responsible for all regulatory reporting and compliance with applicable codes and legislation governing HCHI. Regulatory reporting includes development and preparation of rate filings, performance reporting, and compliance.

Information Technology Salaries and Expenses: 5615

The Information Technology ("IT") staff is responsible for the development, operation, maintenance and security of all business system applications utilized by the utility in its operations. These include the customer information, financial reporting and work management systems. Expenses include salaries and all related costs associated with

the IT Technician. This position reports to the Customer Care Systems Supervisor in the Customer Service Department. In addition, one third of the salary related costs associated with the Customer Care Systems Supervisor are included in this area.

Office Supplies and Expenses: 5620

HCHI records general administration expenses which are not clearly applicable to any departmental group of operating expenses to this account. The expenses are further subdivided by the appropriate type of expense.

Outside Services Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, legal services, labour relations specialists, safety consultants, and rates consultants. Also included are expenses for outside computer labour and materials and the costs associated with the computer internet service provider.

Regulatory Expenses: 5655

Regulatory Expenses include those 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. Annual assessment fees paid to regulatory bodies are included in this expenditure category, which include fixed costs assessed by the OEB and the annual regulatory oversight cost recovery fee assessed by the Electrical Safety Authority ("ESA").

Miscellaneous General Expense: 5665

Miscellaneous General Expense includes expenditures for freight charges on inventory items and the costs of conductor reel deposits.

Electrical Safety Authority Fees: 5680

Expenses under Electrical Safety Authority ("ESA") fees include charges paid to the ESA for permits and inspections.

Table 4
Detailed, Account by Account, OM&A Expenses

OM&A Cost Table

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	Ref.	2007 Actual	Variance from 2006 Actual	Ref.	2008 Actual	Variance from 2007 Actual	Ref.	2009 Bridge	Variance from 2008 Actual	Ref.	2010 Test	Variance from 2009 Bridge	Ref.	Variance from 2006 Actual	Percent Change (%)	Variance from 2008 Actual	Percent Change (%)
Operation																				
5005-Operation Supervision and Engineering	251,220	326,519	75,299	A	349,362	22,843		431,555	82,193	A	492,414	60,859	A	499,249	6,835		172,730	52.90%	67,694	15.69%
5010-Load Dispatching		0	0		0	0		0	0		0	0		0	0		0		0	
5012-Station Buildings and Fixtures Expense		0	0		0	0		0	0		0	0		0	0		0		0	
5014-Transformer Station Equipment - Operation Labour		0	0		0	0		0	0		0	0		0	0		0		0	
5015-Transformer Station Equipment - Operation Supplies and Expenses		0	0		0	0		0	0		0	0		0	0		0		0	
5016-Distribution Station Equipment - Operation Labour	7,337	11,195	3,858		17,379	6,184		22,329	4,950		17,334	(4,995)		17,889	555		6,694	59.79%	(4,440)	-19.88%
5017-Distribution Station Equipment - Operation Supplies and Expenses	10,595	14,930	4,335		15,438	508		16,966	1,528		19,000	2,034		19,570	570		4,640	31.08%	2,604	15.35%
5020-Overhead Distribution Lines and Feeders - Operation Labour	101,844	113,403	11,559		120,354	6,951		107,617	(12,737)		115,403	7,786		120,005	4,602		6,602	5.82%	12,388	11.51%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		0	0		0	0		0	0		0	0		0	0		0		0	
5030-Overhead Subtransmission Feeders - Operation		0	0		0	0		0	0		0	0		0	0		0		0	
5035-Overhead Distribution Transformers- Operation	152,283	260,648	108,365	B	274,858	14,210		186,097	(88,761)	B	212,380	26,283		221,961	9,581		(38,687)	-14.84%	35,864	19.27%
5040-Underground Distribution Lines and Feeders - Operation Labour	23,989	39,801	15,812		47,651	7,850		64,878	17,227		57,554	(7,324)		58,608	1,054		18,807	47.25%	(6,270)	-9.66%
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses		0	0		0	0		0	0		0	0		0	0		0		0	
5050-Underground Subtransmission Feeders - Operation		0	0		0	0		0	0		0	0		0	0		0		0	
5055-Underground Distribution Transformers - Operation	40,967	17,542	(23,425)		11,516	(6,026)		-1,528	(13,044)		15,186	16,714		15,696	510		(1,846)	-10.52%	17,224	-1127.23%
5060-Street Lighting and Signal System Expense		0	0		0	0		0	0		0	0		0	0		0		0	
5065-Meter Expense	197,651	164,296	(33,355)		200,949	36,653		234,187	33,238		257,227	23,040		276,493	19,266		112,197	68.29%	42,306	18.07%
5070-Customer Premises - Operation Labour	8,313	6,149	(2,164)		7,778	1,629		5,995	(1,783)		13,127	7,132		15,294	2,167		9,145	148.72%	9,299	155.11%
5075-Customer Premises - Materials and Expenses		0	0		0	0		0	0		0	0		0	0		0		0	
5085-Miscellaneous Distribution Expense	142,862	204,419	61,557	C	147,906	(56,513)	A	153,967	6,061		186,655	32,688		192,883	6,228		(11,536)	-5.64%	38,916	25.28%
5090-Underground Distribution Lines and Feeders - Rental Paid		0	0		0	0		0	0		0	0		0	0		0		0	
5095-Overhead Distribution Lines and Feeders - Rental Paid		0	0		0	0		0	0		0	0		0	0		0		0	
5096-Other Rent		0	0		0	0		0	0		0	0		0	0		0		0	
Sub-Total	**937,061**	**1,158,902**	**221,841**	D	**1,193,191**	**34,289**		**1,222,063**	**28,872**		**1,386,280**	**164,217**	**B**	**1,437,648**	**51,368**		**278,746**	24.05%	**215,585**	17.64%

OM&A Cost Table

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	Ref.	2007 Actual	Variance from 2006 Actual	Ref.	2008 Actual	Variance from 2007 Actual	Ref.	2009 Bridge	Variance from 2008 Actual	Ref.	2010 Test	Variance from 2009 Bridge	Ref.	Variance from 2006 Actual	Percent Change (%)	Variance from 2008 Actual	Percent Change (%)
Maintenance																				
5105-Maintenance Supervision and Engineering	143,834	81,122	(62,712)	E	98,399	17,277		117,796	19,397		125,994	8,198		129,706	3,712		48,584	59.89%	11,910	10.11%
5110-Maintenance of Buildings and Fixtures - Distribution Stations		0	0		0	0		0	0		0	0		0	0		0		0	
5112-Maintenance of Transformer Station Equipment		0	0		0	0		0	0		0	0		0	0		0		0	
5114-Maintenance of Distribution Station Equipment	89,337	67,382	(21,955)		204,963	137,581	B	215,629	10,666		90,167	(125,462)	C	107,029	16,862		39,647	58.84%	(108,600)	-50.36%
5120-Maintenance of Poles, Towers and Fixtures	228,626	298,799	70,173	F	763,957	465,158	C	641,332	(122,625)	C	637,848	(3,484)		607,398	(30,450)		308,599	103.28%	(33,934)	-5.29%
5125-Maintenance of Overhead Conductors and Devices	536,553	425,852	(110,701)	G	767,659	341,807	D	670,371	(97,288)	D	848,105	177,734	D	900,963	52,858	A	475,111	111.57%	230,592	34.40%
5130-Maintenance of Overhead Services	117,857	133,061	15,204		144,538	11,477		129,686	(14,852)		151,442	21,756		158,103	6,661		25,042	18.82%	28,417	21.91%
5135-Overhead Distribution Lines and Feeders - Right of Way	447,204	227,225	(219,979)	H	613,536	386,311	E	548,666	(64,870)	E	564,461	15,795		556,518	(7,943)		329,293	144.92%	7,852	1.43%
5145-Maintenance of Underground Conduit	1,985	933	(1,052)		1,587	654		13,225	11,638		9,574	(3,651)		10,687	1,113		9,754	1045.44%	(2,538)	-19.19%
5150-Maintenance of Underground Conductors and Devices	16,362	39,713	23,351		16,730	(22,983)		19,345	2,615		37,325	17,980		33,209	(4,116)		(6,504)	-16.38%	13,864	71.67%
5155-Maintenance of Underground Services	53,099	93,030	39,931		72,582	(20,448)		127,255	54,673	F	108,412	(18,843)		111,495	3,083		18,465	19.85%	(15,760)	-12.38%
5160-Maintenance of Line Transformers	49,675	48,373	(1,302)		151,686	103,313	F	161,601	9,915		166,502	4,901		159,370	(7,132)		110,997	229.46%	(2,231)	-1.38%
5165-Maintenance of Street Lighting and Signal Systems		0	0		0	0		0	0		0	0		0	0		0		0	
5170-Sentinel Lights - Labour		0	0		0	0		0	0		0	0		0	0		0		0	
5172-Sentinel Lights - Materials and Expenses		0	0		0	0		0	0		0	0		0	0		0		0	
5175-Maintenance of Meters	13,436	13,623	187		19,118	5,495		10,295	(8,823)		25,366	15,071		26,272	906		12,649	92.85%	15,977	155.19%
5178-Customer Installations Expenses - Leased Property		0	0		0	0		0	0		0	0		0	0		0		0	
5195-Maintenance of Other Installations on Customer Premises		1,683	1,683		1,663	(20)		5,201	3,538		2,048	(3,153)		1,983	(65)		300	17.83%	(3,218)	-61.87%
Sub-Total	**1,697,968**	**1,430,796**	**(267,172)**	**I**	**2,856,418**	**1,425,622**	**G**	**2,660,402**	**(196,016)**	**G**	**2,767,244**	**106,842**	**E**	**2,802,733**	**35,489**		**1,371,937**	95.89%	**142,331**	5.35%

OM&A Cost Table

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	Ref.	2007 Actual	Variance from 2006 Actual	Ref.	2008 Actual	Variance from 2007 Actual	Ref.	2009 Bridge	Variance from 2008 Actual	Ref.	2010 Test	Variance from 2009 Bridge	Ref.	Variance from 2006 Actual	Percent Change (%)	Variance from 2008 Actual	Percent Change (%)
Billing and Collections																				
5305-Supervision	48,002	121,433	73,431	J	128,749	7,316		134,389	5,640		142,969	8,580		144,980	2,011		23,547	19.39%	10,591	7.88%
5310-Meter Reading Expense	327,436	332,761	5,325		293,130	(39,631)		279,893	(13,237)		280,668	775		296,609	15,941		(36,152)	-10.86%	16,716	5.97%
5315-Customer Billing	401,526	486,043	84,517	K	511,791	25,748		536,957	25,166		580,156	43,199		602,980	22,824		116,937	24.06%	66,023	12.30%
5320-Collecting	201,411	153,215	(48,196)		228,735	75,520	H	226,491	(2,244)		250,781	24,290		254,886	4,105		101,671	66.36%	28,395	12.54%
5325-Collecting- Cash Over and Short	39	1,001	962		-135	(1,136)		-7	128		0	7		0	0		(1,001)	-100.00%	7	-100.00%
5330-Collection Charges		0	0		0	0		0	0		0	0		0	0		0		0	
5335-Bad Debt Expense	19,011	98,537	79,526	L	57,092	(41,445)		84,437	27,345		30,000	(54,437)	F	30,000	0		(68,537)	-69.55%	(54,437)	-64.47%
5340-Miscellaneous Customer Accounts Expenses	98,917	53,231	(45,686)		59,293	6,062		41,819	(17,474)		70,761	28,942		73,968	3,207		20,737	38.96%	32,149	76.88%
Sub-Total	**1,096,342**	**1,246,221**	**149,879**	**M**	**1,278,655**	**32,434**		**1,303,979**	**25,324**		**1,355,335**	**51,356**		**1,403,423**	**48,088**		**157,202**	12.61%	**99,444**	7.63%
Community Relations																				
5405-Supervision		0	0		0	0		0	0		0	0		0	0		0		0	
5410-Community Relations - Sundry	27,425	35,158	7,733		32,834	(2,324)		26,110	(6,724)		27,972	1,862		28,836	864		(6,322)	-17.98%	2,726	10.44%
5415-Energy Conservation	610	50,773	50,163		91,012	40,239		12,609	(78,403)	H	18,000	5,391		18,000	0		(32,773)	-64.55%	5,391	42.76%
5420-Community Safety Program		0	0		0	0		0	0		0	0		0	0		0		0	
5425-Miscellaneous Customer Service and Informational Expenses		0	0		0	0		0	0		0	0		0	0		0		0	
Sub-Total	**28,035**	**85,931**	**57,896**	**N**	**123,846**	**37,915**		**38,719**	**(85,127)**	**I**	**45,972**	**7,253**		**46,836**	**864**		**(39,095)**	-45.50%	**8,117**	20.96%

OM&A Cost Table

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	Ref.	2007 Actual	Variance from 2006 Actual	Ref.	2008 Actual	Variance from 2007 Actual	Ref.	2009 Bridge	Variance from 2008 Actual	Ref.	2010 Test	Variance from 2009 Bridge	Ref.	Variance from 2006 Actual	Percent Change (%)	Variance from 2008 Actual	Percent Change (%)
Administrative and General Expenses																				
5605-Executive Salaries and Expenses	80,860	71,032	(9,828)		76,167	5,135		67,824	(8,343)		71,428	3,604		71,428	0		396	0.56%	3,604	5.31%
5610-Management Salaries and Expenses	504,446	544,469	40,023		585,101	40,632		621,393	36,292		638,854	17,461		654,364	15,510		109,895	20.18%	32,971	5.31%
5615-General Administrative Salaries and Expenses	274,349	320,631	46,282		440,996	120,365	I	482,068	41,072		524,809	42,741		542,981	18,172		222,350	69.35%	60,913	12.64%
5620-Office Supplies and Expenses	105,214	93,198	(12,016)		101,010	7,812		110,866	9,856		106,564	(4,302)		112,380	5,816		19,182	20.58%	1,514	1.37%
5625-Administrative Expense Transferred-Credit		0	0		0	0		0	0		0	0		0	0		0		0	
5630-Outside Services Employed	248,450	339,990	91,540	O	285,968	(54,022)	J	362,541	76,573	J	385,077	22,536		402,106	17,029		62,116	18.27%	39,565	10.91%
5635-Property Insurance	14,449	16,702	2,253		14,912	(1,790)		18,069	3,157		18,844	775		19,408	564		2,706	16.20%	1,339	7.41%
5640-Injuries and Damages		0	0		0	0		0	0		0	0		0	0		0		0	
5645-Employee Pensions and Benefits	7,230	0	(7,230)		0	0		0	0		0	0		0	0		0		0	
5650-Franchise Requirements		0	0		0	0		0	0		0	0		0	0		0		0	
5655-Regulatory Expenses	77,664	86,882	9,218		79,392	(7,490)		89,252	9,860		87,070	(2,182)		101,208	14,138		14,326	16.49%	11,956	13.40%
5660-General Advertising Expenses		0	0		0	0		0	0		0	0		0	0		0		0	
5665-Miscellaneous General Expenses	375,456	133,952	(241,504)	P	74,166	(59,786)	K	59,756	(14,410)		57,355	(2,401)		57,455	100		(76,497)	-57.11%	(2,301)	-3.85%
5670-Rent		0	0		0	0		0	0		0	0		0	0		0		0	
5675-Maintenance of General Plant		0	0		0	0		0	0		0	0		0	0		0		0	
5680-Electrical Safety Authority Fees		0			0	0		0	0		0	0		0	0		0		0	
5685-Independent Market Operator Fees and Penalties		0			0	0		0	0		0	0		0	0		0		0	
5695-OM&A Contra Account		0			0	0		0	0		0	0		0	0		0		0	
Sub-Total	**1,688,118**	**1,606,856**	**(81,262)**	**Q**	**1,657,712**	**50,856**		**1,811,769**	**154,057**	**K**	**1,890,001**	**78,232**	**G**	**1,961,330**	**71,328**		**354,474**	22.06%	**149,561**	8.25%
Total Operating, Maintenance and Administration Expenses (before Taxes Other Than Income Taxes)	**5,447,524**	**5,528,706**	**81,182**		**7,109,822**	**1,581,116**		**7,036,932**	**(72,890)**		**7,444,832**	**407,900**		**7,651,970**	**207,138**		**2,123,264**	38.40%	**615,038**	8.74%
Taxes Other Than Income Taxes																				
6105-Property Taxes	54,587	51,609	(2,978)		52,111	502		51,523	(588)		51,937	414		53,447	1,510		1,838	3.56%	1,924	3.73%
Sub-Total	**54,587**	**51,609**	**(2,978)**		**52,111**	**502**		**51,523**	**(588)**		**51,937**	**414**		**53,447**	**1,510**		**1,838**	3.56%	**1,924**	3.73%
Total Operating, Maintenance and Administration Expenses	**5,502,111**	**5,580,315**	**78,204**		**7,161,933**	**1,581,618**		**7,088,455**	**(73,478)**		**7,496,769**	**408,314**		**7,705,417**	**208,648**		**2,125,102**	38.08%	**616,962**	8.70%
Amortization Expenses																				
5705-Amortization Expense - Property, Plant, and Equipment	2,118,125	2,005,672	(112,453)		2,141,647	135,975		2,421,523	279,876		2,796,201	374,678		2,914,312	118,111		908,640	45.30%	492,789	20.35%
5715-Amortization of Intangibles and Other Electric Plant	21,192	20,721	(472)		20,721	0		20,777	57		17,775	(3,002)		17,775	(0)		(2,946)	-14.22%	(3,003)	-14.45%
Sub-Total	**2,139,317**	**2,026,392**	**(112,925)**	R	**2,162,367**	**135,975**	L	**2,442,300**	**279,933**	L	**2,813,976**	**371,676**	H	**2,932,087**	**118,111**	B	**905,694**	44.69%	**489,787**	20.05%
Total Distribution Expense Before Income Taxes	7,641,428	7,606,707	(34,721)		**9,324,300**	**1,717,593**		**9,530,755**	**206,455**		**10,310,745**	**779,990**		**10,637,504**	**326,758**		**3,030,797**	39.84%	**1,106,749**	11.61%

VARIANCE ANALYSIS ON OM&A COSTS

HCHI has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year and including the variances year over year in Exhibit 4, Tab 2, Schedule 2, Table 4 above. Table 4 also provides the percent change from the 2006 Actual (last Board Approved Actual year) to the 2010 Test year and from the 2008 Actual to the 2010 Test year. Before moving to a variance analysis for each account that exceeds the materiality threshold, a summary of total OM&A expenses (excluding amortization) is presented below along with an analysis of the total changes from 2006 Actual to 2010 Test Year.

Table 5 identifies key cost drivers from the last Board Approved rebasing year, 2006 Actual, to the 2010 Test year:

Table 5
OM&A Cost Driver Table

OM&A	2006 Actual Year (Board Approved Year)	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Opening Balance	5,502,111	5,580,315	7,161,933	7,088,455	7,496,769
Labour & Benefit Changes	299,289	239,360	252,164	112,224	143,425
Tree Trimming Services	(219,979)	386,311	(64,870)	15,795	
OEB Plant Inspection Costs & Ground Level Maintenance Program	133,455	615,945	(219,913)	199,490	
Third Party Contractor Costs	(110,701)	147,666	99,673	101,720	57,723

OM&A	2006 Actual Year (Board Approved Year)	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Dist. Station Maintenance	(21,955)	137,581		(125,462)	
PCB Sampling & Testing Program	108,365	103,313	(88,761)	26,283	
IT Network Security Costs	108,907	16,151	(13,281)		
Consultant Costs (Regulatory filings)	87,106	(129,959)	89,854	22,536	
C&DM Program Spending	57,896		(78,403)		
OEB Account Reclassification	(343,281)	22,117			
Miscellaneous Costs	(20,898)	43,133	(49,941)	55,728	7,500
Closing Balance	5,580,315	7,161,933	7,088,455	7,496,769	7,705,417

OM&A Cost Drivers

a) Labour and Benefit Changes

Year over year changes in staff complement and compensation increases are detailed in Exhibit 4, Tab 2, Schedule 7 including Table 14 “Employee Compensation and Benefits” which also provides details of employee complement, base wages, overtime pay, and employee benefits by category; Executive, Management, Non-Union, and Union.

b) Tree Trimming Services

As discussed below in the variance analysis from year to year, line clearing is performed by competent contractors annually on a cyclic basis. The increase and / or decreases year over year represent areas in the cycle that are

scheduled for one year and then postponed to the following year. At the end of 2007 the tree clearing cycle was returned to schedule as per HCHI's maintenance plan with one small area in 2008 postponed to 2009 due to heavy tree conditions in the 2008 year.

c) OEB Plant Inspection Costs & Ground Level Maintenance Program

Costs have increased in this area due to the full deployment of ground level maintenance in conjunction with the distribution plant inspections. This work and related costs are discussed in detail in the variance analysis by OEB APH account below.

d) Third Party Contractor Costs

HCHI has seen an increase in the use of line contractors and associated services to perform various maintenance activities on the distribution system. Contractors have also been utilized to perform and assist with a variety of engineering tasks at HCHI as well as the performing of locates. Refer to the variance analysis below for further details.

e) Distribution Station Maintenance

HCHI's substation projects from year to year are partially planned and partially unplanned based on equipment problems. This results in the fluctuation of costs from year to year. As well, the remediation of soil has been a cost in a few years at the decommissioned distribution stations ("DS"). (Rainham DS in 2007, Forest St. DS in 2008, John DS scheduled for 2009, and Nanticoke DS scheduled for 2010).

f) PCB Sampling and Testing Program

In 2005, a program was started to test all distribution transformers for PCB content. This increased the number of transformers to be changed from year to year based on the number of equipment defects identified and repaired during the PCB sampling and testing program.

g) IT Network Security Costs

Costs increased significantly in 2006 due to the unexpected IT failure that occurred in July 2006. Ongoing upgrades to network security and administration have accounted for a majority of these costs as well as annual IT security audits.

h) Consultant Costs (Regulatory Filings)

Costs were incurred in 2006 to prepare the Cost Allocation Filing as well as the external auditing costs in order to calculate the PILs true-up. In 2008, the majority of the costs represent an outside consultant preparing an Asset Condition Study on behalf of HCHI.

i) C&DM Program Spending

The 2006 costs represent the funds spent on Conservation and Demand Management ("C&DM") programs as part of the Third Tranche funding approved by the OEB. An offsetting amount was recorded as income in 2006. The decrease in 2008 is represented by the end of the C&DM programs as part of the Third Tranche funding approved by the OEB in September 2007. 2008 C&DM programs were funded thru the OPA and recorded in account 1117. Costs recorded in this account in 2008 were on account of HCHI continuing with community based energy conservation programs promoting consumer education and awareness.

j) OEB Account Reclassification

In 2006 two amounts have been reallocated from the Board Approved year, (2004 actual). $(315,726) is on account of Hydro One Networks Inc. ("HONI") Low Voltage Wheeling Charges, reflected in the 2006 Board Approved rate model as a Tier 1 Adjustment for Distribution Expenses as per the 2006 EDR Handbook (refer to 3.2.1 Section C) and recorded in account 5665. Actual charges in 2006 for the HONI Low Voltage charges are recorded to account 4750

per the OEB's accounting guidance issued subsequently in a June 13, 2006 letter.

The balance of $(27,555) is on account of a recalculation of the 2005 Retail Cost Variance Account ("RCVA") balances adjusted and recorded in 2006. HCHI records the incremental costs in this account incurred for the provision of retail services commencing with the retail market opening May 1, 2002. Thus, the RCVA variance between the service fees collected and the incremental expenses incurred related to those service fees are recorded in an offset of this account. For the 2008 year, $22,117 is on account of costs directly related to the collection of customer accounts reallocated to account 5320.

k) Miscellaneous Costs

The cost increases and / or decreases from year to year represent various activities described in the departmental groupings in the variance analysis below. They could include such costs as changes in office equipment maintenance contracts, unforeseen office equipment repairs, bad debt adjustments, rental of a service yard in Dunnville, change in method of delivering collection notices and increases and decreases in legal fees from year to year.

Variance Analysis

As mentioned above, the variance that triggers the required analysis is $53,080 (i.e. materiality threshold) representing 0.5% of HCHI's distribution revenue requirement. HCHI has reviewed the variance of each OEB USoA account to determine where explanations are necessary. An identification reference has been assigned for each variance exceeding the threshold in Table 4 "OM&A Cost Table", and an explanation of each variance is presented in the following section. The cumulative year over year variance analysis provides the net change from the Last Board Approved Rebasing Application (2004 Actual) to the 2010 Test Year, as well as accumulates the net change from the most current Actual, the 2008 Year, as compared to the 2010 Test Year.

2006 ACTUAL VERSUS 2006 BOARD APPROVED

Ref A: 5005 Operation Supervision and Engineering

Operation Supervision and Engineering costs increased by $75,299 compared to the 2006 Board Approved amount. In 2006 HCHI added two new full-time positions, including a GIS Technician and an Engineering Technician, and one part-time position for an operations summer student to assist with the creation of statistical reports and data management. These positions account for $47,792 of the increase. The balance of $27,507 represents contracted technical staff retained to assist with the preparation of Engineering project instruction orders for Renewable Energy Standard Offer ("RESOP") connection impact assessments. The costs associated with connection impact assessments will vary from year to year based on the number of assessments necessary to be completed in the year.

Ref B: 5035 Overhead Distribution Transformers - Operations

This account increased by $108,365 from the 2006 Board Approved (2004 Actual). The amount of the increase is attributable to a program that was in place by 2006 to test all distribution transformer oil for PCB content. In addition to taking an oil sample from

each, nameplate information was also collected for input into the database in the GIS system.

Ref C: 5085 Miscellaneous Distribution Expense

Costs increased by $61,557 from the 2006 Board Approved. The majority of the increase, $53,518, is a result of costs incurred for the rental of two indoor truck bays at Haldimand County's Public Works yard located in Dunnville. This amount includes back rent from January 2004 to December 2005 as well as the rent paid for 2006. HCHI was renting space to park two line trucks in order to service the Dunnville area until November 15, 2006 when HCHI vacated the property. The balance of the increase, $8,039 is attributed to significant increases in the cost of electricity and slight increases in the price of natural gas used at HCHI's service centre, 1 Greendale Drive in Caledonia, from the 2004 base year as compared to 2006 actual.

Ref D: Operations Grouping

The overall variance in the grouping "Operations" is $221,841; an increase in costs from 2006 Actual to the 2006 Board Approved. This amount is a result of the combined increases in accounts referenced in A, B, and C and offset by decreases in account 5055 of $(23,425) and account 5065 of $(33,355).

Costs recorded in account 5055, Underground Distribution Transformers – Operations, are generally as a result of a padmount transformer in-service failure. The decrease of $(23,425) represents reduced activity in 2006. An inspection program for padmounts (as budgeted in 2006) did not take place, and therefore subcontractor costs were not incurred. The decrease in account 5065, Meter Expense, is a result of inaccurate coding in 2004 which was the actual year the 2006 Board Approved was based on. Allocation of materials and labour required to maintain meters was inaccurately coded to account 5065 in 2004. In 2006 these costs have been appropriately allocated to account 5175, Maintenance of Meters.

Ref E: 5105 Maintenance Supervision and Engineering

The decrease of $(62,712) is represented by the Line Supervisor labour hours and truck hours being reallocated to other operations and maintenance accounts in the 2006 actual year as compared to the posting of these labour and truck hours to this account in the 2006 Board approved year. The reallocation represents a more accurate accounting for the Line Supervisor's activities.

Ref F: 5120 Maintenance of Poles, Towers and Fixtures

The increase of $70,173 is a result of an increase in the number of pole replacements required and the use of line contractors and associated services, such as traffic control and vacuum excavation, to replace these defective poles and fixtures that were identified. The beginning of ground level maintenance by the contractor performing the plant inspections has also contributed to the increase in this account. This ground level maintenance could include the following: replacement of guy guards, install molding over exposed down ground, replace ground rod clamps, insert cobra rods, install cobra plugs, and cut unused anchors below grade.

Ref G: 5125 Maintenance of Overhead Conductors and Devices

The significant decrease in this account of $(110,701) is a result of the decrease in the use of a line contractor (approximately half the cost from 2004 (base for Board approved) to 2006 to perform maintenance work on the overhead distribution line facilities.

Ref H: 5135 Overhead Distribution Lines and Feeders – Right of Way

Line clearing is performed by competent contractors annually on a cyclic basis to cover the service territory over a five year period. The large decrease of $(219,979) was a combination of costs recorded in this account for the Board Approved year being higher than normal and the costs recorded for the 2006 Actual year being lower than normal.

For Board Approved, costs included one cycle area with part of another area from a previous year that had not been completed on its regularly scheduled year. For the 2006 year, the budgeted costs were estimated based on previous costs obtained from performing clearing in these areas but when tendered, these costs came in much higher than budget. In order to keep 2006 actual costs in line with that year's budget, the area of clearing was reduced for the 2006 year and line clearing scheduled but not completed in 2006 was postponed to 2007.

Ref I: Maintenance Grouping

The overall variance in the grouping "Maintenance" is $(267,172); a decrease in costs from 2006 Board Approved to the 2006 Actual. This amount is a net effect from the combined decreases and increases in accounts referenced in E, F, G, and H and offset by the increases in account 5150 of $23,351, account 5155 of $39,931, and decrease in account 5114 of $(21,955).

Costs recorded in account 5114, Maintenance of Distribution Station Equipment, are for substation projects within the year. These projects are partially planned and partially unplanned based on equipment problems arising at the stations within the year. The decrease of $(21,955) from 2006 Board approved year to 2006 actual is a direct reflection of the different types of activities and costs associated with those activities taking place in the stations. Account 5150, Maintenance of Underground Conductors and Devices, includes activity resulting from the repair of faulted primary and secondary cable. This activity is driven from the number of repairs and the complexity of the required repairs. The increase in cost of $23,351 reflects the increased activity and / or complexity of repairs required in 2006. Activity account 5155, Maintenance of Underground Services, involves the repair of faulted secondary services. This activity is driven from the number of repairs and the complexity of the required repairs. The increase in cost of $39,931 reflects the increased activity and / or complexity of repairs required in 2006.

Ref J: 5305 Supervision

Total expenses increased by $73,431 from the 2006 Board Approved. The majority of the increase, $53,904, is on account of a new full-time position added, Customer Care Systems Supervisor. This new position was created to take on the responsibility of retail settlement, conservation, and information technology ("IT"), including IT with respect to smart meter implementation. The balance of the increase, $19,527, is a result of labour rate increases over the two year period from 2004 to 2006 for the Customer Service Supervisor as well as associated expenses and overtime incurred in 2006.

Ref K: 5315 Customer Billing

The increase of $84,517 from the 2006 Board Approved year to the 2006 Actual year is partially due, in the amount of $43,635, to a full-time position previously allocated to account 5320, Collecting, now being accounted for in this account after department restructuring. The remaining balance of $40,882 is on account of additional costs associated with HCHI entering into two new copier / printer leases to replace existing owned equipment that were at the end of their useful life, unusual repairs to an in-house bill stuffing machine that was retired at the end of 2006, labour rate increases over the two year period, 2004 to 2006, and increases in postage rates, bill stock and envelopes.

Ref L: 5335 Bad Debt Expense

Bad debt expense increased by $79,526 from the 2006 Board Approved year to the 2006 Actual year. A portion of this increase represents write-offs of third party receivables, typically on account of damages to the distribution system from car accidents, in the amount of $7,517 as compared to $0 for third party receivables written off in the Board Approved year. The remaining balance of $72,009 is on account of an increase to the allowance in the 2006 Actual year to represent anticipated write-offs on account of uncollectible customer accounts.

Ref M: Billing and Collections Grouping

The overall variance in the grouping "Billing and Collections" is $149,879, an increase in costs from 2006 Actual to the 2006 Board Approved. This amount is a result of the combined increases in accounts referenced in J, K, and L and offset by decreases in account 5320 of $(48,196) and account 5340 of $(45,686).

In account 5320, Collection Charges, the decrease of $(48,196) from the 2006 Board Approved year to the 2006 Actual year is on account of the one full-time position transferred to 5315, Customer Billing, after department restructuring. The variance of $4,561 between the increase in 5315 and the decrease in 5320 for this reallocation is due to overtime incurred by this individual in the Board Approved year as compared to the 2006 Actual. Account 5340, Miscellaneous Customer Accounts Expenses, has decreased by $(45,686) from the 2006 Board Approved year to the 2006 Actual year partially on account HCHI changing its wholesale settlements provider. This change resulted in a reduced monthly cost representing $(18,131) of the decrease. The balance of $(27,555) is on account of a recalculation of the 2005 Retail Cost Variance Account ("RCVA") balances adjusted and recorded in 2006. HCHI records the incremental costs in this account incurred for the provision of retail services once the retail market opened May 1, 2002. Thus, the RCVA variance between the service fees collected and the incremental expenses incurred related to those service fees are recorded in an offset of this account.

Ref N: Community Relations Grouping

The increase of $57,896 for this grouping represents the funds spent on Conservation and Demand Management programs as part of the Third Tranche funding approved by the OEB. An offsetting amount was recorded as income in 2006.

Ref O: 5630 Outside Services Employed

The costs for professional fees and consulting work allocated to this account have increased by $91,540 from Board Approved to 2006 Actual. The majority of the increase, $64,876, is costs allocated to the rate consultant's work in order to file the Cost Allocation Review Filing with the OEB. Additional auditing work was performed in 2006 in the amount of $22,230 for the review of future income taxes, and the calculation of the PIL's true-up. External computer labour costs also increased by $34,685 on account of an additional support agreement with a third party for IT network administration, annual web support fees for a Conservation website, and an increase in annual software maintenance support. A decrease of $(31,226) was spent on legal services in 2006 as compared to 2004. Significant legal fees were incurred in 2004 with respect to the Stewart line relocation case which was ultimately found in favour of HCHI, with costs to be recovered gradually, secured against the property. No significant legal issues arose during 2006. The balance of the increase in this account of $975 is on account of an increase in spending on training and development seminars.

Ref P: 5665 Miscellaneous General Expenses

Total expenses allocated to this account decreased by $(241,504) from the 2006 Board Approved to 2006 Actual. $(315,726) is on account of Hydro One Networks Inc. ("HONI") Low Voltage Wheeling Charges reflected in the 2006 Board Approved rate model as a Tier 1 Adjustment for Distribution Expenses as per the 2006 EDR Handbook (refer to 3.2.1 Section C). Actual charges in 2006 for the HONI Low Voltage charges are recorded to account 4750 per the OEB's accounting guidance issued in a June 13, 2006 letter. The remaining balance of $74,222 represents costs allocated to this account related to an investigation and restoration following an unexpected IT failure in July 2006. Examples of additional costs incurred due to the unexpected IT failure are employee overtime labour hours, 3rd party IT support, and an outside consultant to audit the failure and IT systems.

Ref Q: Administrative and General Expenses Grouping

The "Administrative and General Expenses" grouping has decreased by $(81,262) from 2006 Board Approved to 2006 Actual. This is a result of the net effect from the decreases as referenced in letters O & P above and the two increases in account 5610 of $40,023 and account 5615 of $46,282.

Account 5610, Management Salaries and Expenses, has increased by $40,023 from 2006 Board Approved to 2006 Actual. This increase is on account of labour rate increases over the two year period, 2004 to 2006, and payroll overhead percentage increases over the two years; 40% to 45% effective January 1, 2005; and 45% to 50% effective January 1, 2006. The burden increases were necessary in order to capture the cost of employee benefits including group insurance and all payroll taxes. Costs allocated to account 5615, General Administrative Salaries and Expenses, have increased by $46,282 from 2006 Board Approved to 2006 Actual. An increase of $52,157 is attributed to the difference between the Regulatory Specialist position, which was half a full-time position and no longer in existence after 2004, and the creation of a new position in 2005, Accounting Supervisor. The balance of $(5,875) is a net difference between Pay Equity payouts occurring in 2004 and 2005 but not in 2006 and labour rate increases over the two year period, 2004 to 2006.

Ref R: 5705 / 5715 Amortization Expense – Property, Plant & Equipment and Intangibles

Actual amortization expense in 2006 decreased by $(112,925) from the 2006 Board Approved levels. The 2006 Board Approved amount is based on 2004 Actual and two Tier 1 Rate Base adjustments. The majority of the costs for the two Tier 1 rate base adjustments were posted to capital late 2006 and into 2007 (C&DM qualifying investment from 3rd tranche funds and wholesale meter upgrades). This would account for a small portion of the decline in amortization from the Board Approved. The balance of the decrease can be attributed to HCHI's conversion from a manual amortization

calculation to a computerized version using the fixed asset module in the existing financial reporting software package. Two issues arose with the conversion;

1. Accounting for Amortization
   a. Manual calculation – 12 months amortization calculated on additions regardless of acquisition date; and
   b. Computerized calculation – calculates monthly amortization based on remaining life, and only amortizes for the remaining months in the year from acquisition date – a more robust matching of costs method.
2. Distribution Plant Assets – Pre-Amalgamation (Oct. 31, 2000) Additions
   a. Manual amortization schedules – assets recorded at net book value at date of amalgamation on new company's books, HCHI. Assets were setup on manual schedules to be fully amortized at the end of their useful life. For example, O/H Conductor NBV from old Haldimand Hydro Electric Commission ("HHEC") recorded as $1,175,000 with annual amortization of $64,910 for 5 years; $62,600 for 2 years; $58,600 for 3 years; $53,800 for 1 year; and so forth.
   b. Computerized calculation – the remaining life of the group of assets had to be estimated based on the annual amortization in the manual schedules. The attempt was made to "smooth" out the remaining amortization to be close to the original manual schedule, as the module takes the NBV at the beginning of the year and equally amortizes over the remaining life of the asset. This resulted in less amortization taken initially on these assets at time of conversion and spread out equally to remaining years.

2007 ACTUAL VERSUS 2006 ACTUAL

Ref A: 5085 Miscellaneous Distribution Expense

This account has decreased by $(56,513) from 2006 Actual to 2007 Actual. As indicated in the analysis for the 2006 Board Approved to the 2006 Actual, rental of two indoor truck bays at Haldimand County's Dunnville Public Works yard ended in 2006 which was utilized to provide a local service centre for HCHI staff in the Dunnville area. This operation was centralized at the main service centre in Caledonia, thus eliminating the rental cost. The decrease in costs from 2006 to 2007 associated with this rental is $(46,333). This is larger than one year's worth of rental fees as back rent for the years 2004 and 2005 was charged and paid for in 2006 as indicated in the analysis of this account in the 2006 Actual Year. The balance of the decrease of $(10,180) represents additional credits received in 2007 from the sale of scrap metal.

Ref B: 5114 Maintenance of Distribution Station Equipment

As indicated in the analysis for the Board Approved to the 2006 Actual, substation projects within the year are partially planned and partially unplanned based on equipment problems arising at the stations. The major contributors to the increase of $137,581 in 2007 as compared to 2006 were the unscheduled replacement of a station distribution transformer and the remediation of soil at one decommissioned distribution station site (Rainham DS).

Ref C: 5120 Maintenance of Poles, Towers, and Fixtures

The costs charged to this account for 2007 have increased by $465,158 over 2006. A portion of this increase, $64,108, can be attributed to labour and truck cost due to the hiring of one additional apprentice lineman in 2007 and the allocation of additional labour and truck hours to this account in 2007 as compared to 2006. Two major factors are responsible for the remaining $401,050 increase in costs from 2006 to 2007. The

first is the full deployment of ground level maintenance in conjunction with the distribution plant inspections. This work involves making repairs accessible from the ground, such as; the installation of notice signs, replacing guy guards, u-guards, remaking grounding connections, repairing guy wires, etc. The second factor is the hiring of a line contractor to perform maintenance work to poles and fixtures over and above what HCHI resources could allocate work time to. This maintenance work mostly involved the replacement of defective poles. This correspondingly increases material costs, direct costs, and subcontractor costs, such as; traffic control, vacuum excavation, landscaping repairs, and backfilling material (screenings).

Ref D: 5125 Maintenance of Overhead Conductors and Devices

This account has increased by $341,807 from 2006 Actual to 2007 Actual. The rationale for the increase in this account is the same as indicated in the analysis for account 5120. The portion of this increase attributed to additional labour and truck hours and the one additional apprentice lineman is $126,912 and the balance of $214,895 can be attributed to the two major factors described above in account 5120; that is full deployment of ground level maintenance in conjunction with the distribution plant inspections and the hiring of a line contractor to perform maintenance work to overhead conductors and devices.

Ref E: 5135 Overhead Distribution Lines & Feeders-Right of Way

As indicated in the analysis for 2006 Board Approved versus 2006 Actual, line clearing is performed annually on a cyclic basis to cover the service territory over a five year period. The increase in 2007 of $386,311 is a direct result of the work postponed in 2006 to keep the costs within the budget for the 2006 year. In 2007 the regular tree trimming cycle was completed as well as the carryover from 2006. At the end of the year 2007, the tree clearing cycle was returned to schedule as per HCHI's maintenance plan.

Ref F: 5160 Maintenance of Line Transformers

The costs charged to this account have increased by $103,313 in 2007 as compared to 2006 Actual. The number of transformers changed in 2006 totaled 5 units while in 2007 37 units were changed which resulted in a significant material cost increase. There was a corresponding increase in labour and truck hours to install these additional units. Subcontractor costs also increased in 2007 due to a number of equipment defects identified and repaired during the PCB sampling and testing program.

Ref G: Maintenance Grouping

The overall variance in the grouping "Maintenance" is $1,425,622; an increase in costs from 2006 Actual to the 2007 Actual. This amount is a net effect from the combined increases in accounts referenced in B, C, D, E, and F and offset by the decreases from account 5150 of $(22,983), and account 5155 of $(20,448).

Total expenses in account 5150, Maintenance of Underground Conductors and Devices, have decreased by $(22,983) in 2007 as compared to 2006 Actual. The decreased costs reflect the decreased activity and / or complexity of the required repairs of faulted primary and secondary cable in 2007 as compared to the activity in 2006. In account 5155, Maintenance of Underground Services, expenses have decreased by $(20,448) in 2007 as compared to 2006 Actual. The decreased costs reflect the decreased activity and / or complexity of the required repairs of faulted secondary services in 2007 as compared to the activity in 2006. Underground locates were contracted out in 2007 which increased subcontractor costs but this increase was offset by the reduction of HCHI labour.

Ref H: 5320 Collecting

This account has increased by $75,520 from 2006 to 2007. $43,133 is on account of a change in the method for delivery of collection notices from mail to being hand delivered to customers. In addition, $22,117 is on account of a reallocation of bill stock,

envelopes and postage costs directly related to the collection of customer accounts to 5320. The remaining variance of $10,270 is a result of the traditional increases in labour rates.

Ref I: 5615 General Administrative Salaries and Expenses

The costs allocated to this account have increased by $120,365 from 2006 Actual to 2007 Actual. An increase of $58,531 is attributed to the addition of a new full-time position, IT Technician, in 2007 and $23,565 is on account of the addition of a Co-op Accounting Student also in 2007. The remaining $38,269 is a result of the traditional increases in labour rate and planned overtime on account of special projects in 2007.

Ref J: 5630 Outside Services Employed

The costs for professional fees and consulting work allocated to this account have decreased by $(54,022) from 2006 Actual to 2007 Actual. This decrease is a net effect between computer labour increases and decreases in consulting fees and audit expenses. The increase in computer labour of $75,937 is partially on account of additional spending in 2007 for website design and support for www.haldimandcountyhydro.ca in the amount of $15,000; performance of an IT security audit of $16,578 on account of IT failure in prior year; additional support agreement with third party for IT network administration of $8,082; additional support fees of $21,600 from billing software vendor for deregulation components; $8,000 for increases in annual software maintenance support; and $6,677 on account of additional fees for internet services and supplies. The decrease in consulting fees and auditing work of $(129,959) is on account of additional services performed in 2006 as compared to not being required in 2007 for rate applications, cost allocation review, future income tax work, and PIL's true-up.

Ref K: 5665 Miscellaneous General Expenses

Total expenses allocated to this account decreased by $(59,786) from the 2006 Actual to 2007 Actual. $(74,222) is on account of the reduction of costs incurred in 2006 due to the IT failure, $8,754 additional spending in 2007 on reel deposits for conductor as compared to 2006, and the cost of restocking charges for returned stock items to vendors of $5,682.

Ref L: 5705 / 5715 Amortization Expense – Property, Plant & Equipment and Intangibles

The actual amortization expense in 2007 increased by $135,975 as compared to the expense in 2006. This increase is related to the 2007 capital expenditures of approximately $2,900,000.

2008 ACTUAL VERSUS 2007 ACTUAL:

Ref A: 5005 Operation Supervision and Engineering

The total increase in costs charged to this account from 2007 Actual to 2008 Actual is $82,193. A portion of the increase, $25,146, is the net effect of two new positions in 2008, an Engineering Technician and a Lines Clerk with the elimination of one Line Supervisor position. $45,000 of the increase is attributed to costs in 2008 associated with connection impact assessments with the actual fee paid by the applicant in 2007 as fees are paid up front prior to work being performed. The remainder of the variance, $12,047, is representative of the traditional negotiated labour rate increases each year.

Ref B: 5035 Overhead Distribution Transformers - Operation

This account has decreased from 2007 Actual to 2008 Actual by $(88,761). This is on account of the PCB testing of all distribution transformers, started in 2005, nearing completion by the end of 2007. In 2008 only a few transformers with difficult access issues remained. The decrease in cost reflects the change in resources required to test the remaining transformers. In addition, much less repair work (driven by the PCB testing program) was required in 2008 in association with the reduced number of transformers required to be tested.

Ref C: 5120 Maintenance of Poles, Towers and Fixtures

Costs charged to this account decreased by $(122,625) from the 2007 Actual to the 2008 Actual. This was a net effect of an increase in subcontractor costs and a decrease in other costs. The increase of $48,200 is a result of maintenance to off road primary line sections; a task that had not been completed in many years. Due to the inaccessibility of the lines it was determined that inspections and corrective maintenance on defects needed to be performed. This inspection utilized line contractors and was very labour intensive consuming very little material. It involved inspecting and replacing or repairing pole fixtures and a limited number of poles. In

anticipation of the 2008 inspection cycle, date nails, asset signs, and public warning signs for installation on poles were purchased in 2007 resulting in a decrease in direct purchases in 2008 of $(27,680). In addition, the mass Replacement of Poles program as discussed in the 2007 Actual comparison to the 2006 Actual year was coded to capital in 2008. This has a decrease effect of $(143,145) on material, labour, and truck costs in 2008.

Ref D: 5125 Maintenance of Overhead Conductors and Devices

This account has decreased by $(97,288) from 2007 Actual to 2008 Actual. The rationale for the decrease in this account is the same as indicated in the analysis for account 5120. The mass Replacement of Poles program as discussed in the 2007 Actual comparison to the 2006 Actual year was coded to capital in 2008. This has a decrease effect on material, labour, and truck costs in 2008.

Ref E: 5135 Overhead Distribution Lines & Feeders-Right of Way

As indicated in the analysis for 2006 Board Approved versus 2006 Actual, line clearing is performed annually on a cyclic basis to cover the service territory over a five year period. The decrease in 2008 of $(64,870) is a direct result of the 2006 work postponed and completed in 2007 as well as the regular 2007 cycle making 2007 higher than normal. At the end of the year 2007, the tree clearing cycle was returned to schedule as per HCHI's maintenance plan. This decrease is also caused by a postponement in 2008 to the 2009 year for one small area. This was postponed in order to keep costs in line with budget as there were heavy tree conditions in this area.

Ref F: 5155 Maintenance of Underground Services

Total expenses have increased by $54,673 in 2008 as compared to 2007 Actual. The increased costs reflect the increased activity and / or complexity of the required repairs of faulted secondary services in 2008 as compared to the activity in 2007.

Ref G: Maintenance Grouping

The overall variance in the grouping "Maintenance" is $(196,016); a decrease in costs from 2007 Actual to the 2008 Actual. This amount is a net effect from the combined increases and decreases in accounts referenced in C, D, E, and F and the increase from account 5105 of $19,397.

Account 5105, Maintenance Supervision and Engineering, has increased by $19,397 from 2007 Actual to 2008 Actual. This increase is the net effect of two new positions in 2008, an Engineering Technician and an Operations Line Clerk with the elimination of one Operations Line Supervisor position. A portion of labour hours is recorded to this account as well as account 5005.

Ref H: 5415 Community Relations & Energy Conservation

The decrease of $(78,403) from the 2007 Actual year to 2008 Actual year is on account of the end of C&DM programs as part of the Third Tranche funding approved by the OEB in September 2007. 2008 C&DM programs were funded thru the OPA and recorded in account 1117. Costs recorded in this account in 2008 were on account of HCHI continuing with community based energy conservation programs promoting consumer education and awareness.

Ref I: Community Relations Grouping

The decrease of $(85,127) for this grouping is largely due to the decrease in account 5415, reference H above. The remaining balance of $(6,724) is on account of less activity in account 5410, Community Relations - Sundry.

Ref J: 5630 Outside Services Employed

This account has increased by $76,573 from 2007 Actual to 2008 Actual year expenses. The primary reason is the preparation of a Distribution Asset Condition Assessment by a third party consultant in the amount of $72,350. Auditing services also increased by

$17,504 in 2008 from 2007 for the preparation of audited financial statements and corporate income tax returns. The costs spent on an IT security audit and website design in 2007 were not required in 2008. The annual increases in software maintenance support were more than offset by these two cost reductions for a net decrease of $(13,281).

Ref K: Administrative and General Expenses Grouping

The "Administrative and General Expenses" grouping has increased by $154,057 from 2007 Actual to 2008 Actual. This is a result of the increase referenced in J above and the two increases in account 5610 of $36,292 and account 5615 of $41,072.

The Management Salaries and Expenses, account 5610, have increased by $36,292 from 2007 Actual to 2008 Actual. This increase is on account of labour rate increases and on account of additional "at work" versus vacation taken hours in 2008 as compared to 2007 by Management. These additional "at work" hours worked are booked to this account, 5610, instead of the payroll burden vacation account, 5645. This results in the vacation time not being taken but carried over to 2009 to either take by May 31, 2009 or to have paid out. The costs allocated to account 5615, General Administrative Salaries and Expenses, have increased by $41,072 from 2007 Actual to 2008 Actual. An increase of $29,301 is attributed to the IT Technician position charged for a full 12 months in 2008 as compared to 9 months in 2007 (position added April 2007). The remaining $11,771 is a result of labour rate increases in 2008.

Ref L: 5705 / 5715 Amortization Expense – Property, Plant & Equipment and Intangibles

The actual amortization expense in 2008 increased by $279,933 as compared to the expense in 2007. This increase is partially on account of a change in accounting policy in 2008. In 2007 and prior, truck amortization was allocated with net overhead burdens. Effective January 1, 200 it is no longer allocated as part of the burden calculation. This accounts for $120,219 of the increase. The remaining $159,714 is related to the 2008

capital expenditures of approximately $4,400,000. ($500,000 General and Administrative Assets and $3,900,000 Distribution Assets.)

2009 BRIDGE YEAR VERSUS 2008 ACTUAL

Ref A: 5005 Operation Supervision and Engineering

The total increase in costs charged to this account from 2008 Actual to 2009 Bridge year is $60,859. A portion of the increase, $20,439, is on account of additional third party engineering work required for ESA audits, equipment approvals, and reliability centered maintenance plans. Additional costs in 2009 for a new copier / printer lease and maintenance agreement for the Operations and Engineering departments in the amount of $25,798 represent another portion of this increase. $40,718 is attributed to labour rate increases for the year and additional hours worked allocated to this account. The remaining balance of $(26,096) is on account of RESOP connection impact assessment (”CIA”) fees and expenses. In 2009 there was little allocated to this account for CIA’s as compared to the extra costs charged in 2008.

Ref B: Operations Grouping

The overall variance in the grouping “Operations” is $164,217, an increase in costs from 2008 Actual to the 2009 Bridge Year. This amount is a result of the increase in account 5005 referenced in A above and the combined increases in account 5035 of $26,283, account 5055 of $16,714, account 5085 of $32,688, and account 5065 of $23,040.

Costs recorded in account 5035 Overhead Distribution Transformers – Operations, has increased from 2008 Actual to 2009 Bridge year by $26,283. This is on account of a large increase in the forecast for material costs for 2009 over 2008 by $54,024. The 2009 budget was based on prorated actual in 2008 on known costs for the first 8 months of the year. The majority of the work took place within those 8 months (not known at the time of the budget preparation) resulting in the 2009 budgeted material costs being over estimated. The offsetting decrease in costs from 2008 to 2009 is a result of the testing of transformers for PCB content concluding in 2008, resulting in the additional subcontractor costs in 2008 not required in 2009 in the amount of $(27,741).

Costs recorded in account 5055 Underground Distribution Transformers – Operations, are generally as a result of a padmount transformer in service failure. The increase of $16,714 represents an increased activity in 2008. Account 5085 Miscellaneous Distribution Expense, has increased by $32,688 from 2008 Actual to 2009 Bridge year. In preparation of the 2009 budget, the amount received for the sale of scrap metal is not considered and does not form part of the costs for account 5085 in the 2009 Bridge year. The extent of the recovery for scrap material is unknown at the time of budget preparation and therefore not forecast. The amount of scrap dollars collected in 2008 was $(32,799) versus $0 in the 2009 forecast, the major contributor to the variance of $32,688. The costs charged to account 5065 Meter Expense, have increased by $23,040 from 2008 Actual to 2009 Bridge. This is on account of the additional hours allocated to this account in 2009 for repairs to meter bases in order to make ready for the smart meter installation.

Ref C: 5114 Maintenance of Distribution Station Equipment

Costs charged to this account decreased by $(125,462) from the 2008 Actual to the 2009 Bridge year. This is on account of the unexpected costs that were spent in 2008 and would not reoccur in the 2009 spending. In 2008, the costs charged to this account exceeded budget by 65%. This occurred due to major defects that were found (but not anticipated) and repaired in stations where planned maintenance was scheduled. In addition to this, a number of unexpected repairs to station equipment were required. An example would be the theft of copper at one station. Labour, material, truck, and direct purchase costs exceeded budget levels due to the necessary repairs. In 2009 planned maintenance activities are expected to be on budget but there is always uncertainty and risk that unplanned events will occur.

Ref D: 5125 Maintenance of Overhead Conductors and Devices

This account has increased by $177,734 from 2008 Actual to 2009 Bridge year. In 2008 it was anticipated that a line contractor would be utilized to make small repairs to the

distribution system which did not take place. In addition to this HCHI's maintenance programs were scaled back to allow resources to perform other work in the distribution system. The net effect of this was that actual expenditures in 2008 were less than budget. In 2009 it is anticipated that maintenance programs will be fully implemented and the allocation of funds will be spent.

Ref E: Maintenance Grouping

The overall variance in the grouping "Maintenance" is $106,842; an increase in costs from 2008 Actual to the 2009 Bridge year. This amount is a net effect from the combined increases and decreases in accounts referenced in C, and D and the increases from account 5130 of $21,756, account 5135 of $15,795, and account 5150 of $17,980.

Total expenses in account 5130 Maintenance of Overhead Services, has increased by $21,756 from the 2008 Actual to the 2009 Bridge year. Costs incurred in this account are a result of field and equipment conditions. These conditions vary from year to year. The increase of $15,795 in account 5135 Overhead Distribution Lines and Feeders – Right of Way, is a result of the postponement of tree / line clearing activities in 2008 to the 2009 year for one small area. This was postponed in order to keep costs in line with budget as there were heavy tree conditions in this area. The balance increase of $17,980 in account 5150 Maintenance of Underground Conductors and Devices, reflects the increased trend for activity and / or complexity of the required repairs of faulted primary and secondary cable in 2009 as compared to the activity in 2008.

Ref F: 5335 Bad Debt Expense

The bad debt expense has decreased by $(54,437) from 2008 to 2009. A portion of this decrease, in the amount of $(15,436), represents the decline in anticipated write-offs of third party receivables, typically on account of damages to the distribution system from car accidents, from $20,436 in 2008 to $5,000 in 2009. The adjustment to the

allowance has decreased by $39,001 representing a decrease in the anticipated write-offs on account of uncollectible customer accounts.

Ref G: Administrative and General Expenses Grouping

The "Administrative and General Expenses" grouping has increased by $78,232 from 2008 Actual to 2009 Bridge. This is a result of the increases in account 5610 of $17,461, account 5615 of $42,741, and account 5630 of $22,536.

The Management Salaries and Expenses, account 5610, have increased by $17,461 from 2008 Actual to 2009 Bridge. This increase is on account of labour rate increases. The costs allocated to account 5615 General Administrative Salaries and Expenses, have increased by $42,741 from 2008 Actual to 2009 Bridge year. An increase of $16,625 is attributed to an additional 6 months of labour costs charged in 2009 as compared to 2008 for the Co-op Accounting Student position. A co-op student was hired for each term of the 2009 year versus only two work terms in 2008. The remaining balance of $26,116 is a result of labour rate increases in 2009, reallocation of some postage costs to this account, an increase in training and development costs, and an increase in costs associated with the Accounting Clerk position for three months due to a leave in 2008 where the position was filled temporarily on a contract basis at a lower rate of pay. The increase of $22,536 in account 5630 Outside Services Employed, is on account of additional services required in 2009 versus 2008 required to prepare the 2010 rate application. The total of these costs has been spread over 4 years; however, the inclusion of one-fourth of these costs still results in an increase over 2008, which included the Distribution Asset Condition Study (LRAM / SSM study – $12,000; Distribution Loss Assessment - $40,000; Rates Consultant - $37,500; Legal - $30,000).

Ref H: 5705 / 5715 Amortization Expense – Property, Plant & Equipment and Intangibles

The actual amortization expense in 2009 increased by $371,676 as compared to the expense in 2008. $105,015 of this increase is on account of the CIS Conversion assets being placed into service in 2009, creating an amortization expense for the first year, 2009, the implementation year of the new billing system. The remaining $266,661 is related to the 2009 capital expenditures of approximately $4,200,000 ($900,000 General & Admin assets and $3,300,000 Distribution assets).

2010 TEST YEAR VERSUS 2009 BRIDGE YEAR

Ref A: 5125 Maintenance of Overhead Conductors and Devices

This account has increased by $52,858 from 2009 Bridge year to 2010 Test year. In 2009 there is a cost to perform 11 kilometres of off road distribution inspection and maintenance. This activity is not required in 2010 as part of HCHI's maintenance plan resulting in $(5,467) decrease. The offsetting increase of $58,325 is a result of additional hours (calculated by trending historical costs) allocated to this account as well as traditional labour and truck rate increases.

Ref B: 5705 / 5715 Amortization Expense – Property, Plant & Equipment and Intangibles

The actual amortization expense in 2010 increased by $118,111 as compared to the expense in 2009. This variance is related to the 2010 capital expenditures of approximately $3,310,000 ($635,000 General and Administrative Assets, and $2,675,000 Distribution Assets).

OM&A SPECIFIC FILING REQUIREMENTS

As detailed in the Filing Requirements, HCHI is providing the OM&A specific filing requirements outlined as the following:

1. One Time Costs – detailed in Table 6, "Regulatory Cost Schedule", with proposal to recover over the duration of the cost of service plus IRM term; that is 4 years (costs related to 2010 Rate Application only). One-time costs related to regulatory items, such as the cost allocation review filing and 2006 EDR preparation that have incurred in past years, have already been fully expensed in the year of occurrence.

2. Regulatory Costs - detailed in Table 6, "Regulatory Cost Schedule", that are ongoing, (occur every year), are fully expensed in the year that they are incurred and one-time regulatory costs related to the preparation of the 2010 Rate Application are to be recovered over the duration of the cost of service plus IRM term; that is 4 years. Costs in Table 6 below related to the preparation of the 2010 Cost of Service Rate Application under the "One-Time Costs" section represent one-fourth of the full amount.

3. Low-Income Energy Consumer Programs (LEAP) – HCHI has not included any costs related to LEAP within its cost of service rate application.

4. Green Energy and Green Economy Act, 2009 (Green Energy Act) – HCHI has not included any special purpose charges within its cost of service rate application related to the Green Energy Act.

5. Charitable Donations – HCHI does not make charitable donations because of its status as a municipally-owned entity.

Table 6 – Regulatory Cost Schedule

Regulatory Cost Category	USoA Account	2006 Board Approved	2006 Actual Year	2007 Actual Year	2008 Actual Year	2009 Bridge Year	% Change Bridge vs 2008 Actual	2010 Test Year	% Change Test vs Bridge Year
Ongoing Costs:									
OEB Annual Assessment	5655	$ 68,840	$ 75,768	$ 63,542	$ 71,160	$ 73,296		$ 75,428	
OEB Section 30 Costs (OEB Initiated)	5655		$ 773	$ 2,626	$ 4,855	$ 2,000		$ 2,000	
OEB Annual Registration Fee	5655		$ 800	$ 800	$ 800	$ 800		$ 800	
ESA Regulatory Oversight Cost Recovery	5655	$ 8,824	$ 9,541	$ 9,444	$ 10,411	$ 10,974		$ 10,980	
One-Time Costs:									
Consultant Costs –Regulatory (2006 EDR, Cost Allocation, etc)	5630	$ 35,438	$ 91,923	$ 7,603	$ 79,586				
Publication of Notice of Application (IRM's)	5655			$ 2,980	$ 2,025				
OEB Section 30 Costs (2010 Rate Application)	5655							$ 12,000	
Legal Costs – Regulatory (2010 Rate Application)	5630					$ 7,500		$ 15,000	
Consultant Costs –Regulatory (2010 Rate Application)	5630					$ 22,375		$ 28,625	
USoA Account Total	5655	$ 77,664	$ 86,882	$ 79,392	$ 89,251	$ 87,070	(2.44%)	$101,208	16.24%
USoA Account Total	5630	$ 35,438	$ 91,923	$ 7,603	$ 79,586	$ 29,875	(62.46%)	$ 43,625	46.03%

Note: Consultant Costs associated with the preparation of the 2010 Rate Application consist of a Rates Consultant, LRAM / SSM preparation, Distribution Loss Study report, and the calculation of site specific loss factors related to the new rate class, Embedded Distributor – Hydro One Networks Inc.

CHARGES TO AFFILIATES FOR SERVICES PROVIDED

Introduction

Haldimand County Hydro Inc. currently performs ongoing streetlight maintenance for The Corporation of Haldimand County and water billing and sentinel light services for its affiliate Haldimand County Energy Inc. ("HCEI"). Actual cost including labour, labour burden, stores material and burden, along with vehicle costs are charged to HCEI.

A summary of charges to affiliates for services provided in 2006 Actual and 2007 Actual, 2008 Actual together with the projections for the 2009 Bridge Year and 2010 Test Year, are shown in the following Table 7, filed as per the "Filing Guidelines" (*Appendix 2-M*). Some of these charges include:

- Tree trimming and removals which occur when such work benefits both the utility and the municipality but the utility's contractor does the work; and
- Pole relocations which occur in conjunction with road widening.

Summary of Charges to / from Affiliates for Services Provided

TABLE 7
HCHI's CHARGES TO AFFILIATES

ACTIVITY	2006 Actual	2007 Actual	2008 Actual	2009 Forecast	2010 Forecast
HCHI Charges to Haldimand County:					
Street Light Maintenance	$90,746	$64,606	$122,858	$125,648	$100,000
Street Light Connection Audit (50% cost sharing with County)	$9,750				
Tree Trimming & Removals (Cost share to County)	$8,538	$12,456	$20,132	$6,999	
Pole Relocations or "New" Pole Installs (Requested by County)	$2,833		$9,902	$5,589	
Supply & Install of Banner Pole Structures		$25,196			
Environmental Remediation at DS on Forest St., Dunnville (49% cost share to County)				$55,523	
HCHI Charges to HCEI:					
Water & Wastewater Billing & Collecting Administrative Fee	$323,139	$342,268	$355,830	$359,823	$359,823
Sentinel Light Maintenance	$19,875	$15,975	$14,531	$17,274	$16,049
Billing & Collecting Labour for Sentinel Lights	$2,660	$2,617	$2,495	$2,529	$2,529
Management & Administrative Salaries	$23,369	$24,376	$25,541	$26,241	$27,027
HCHI Charges to HCUI:					
Management & Administrative Salaries	$23,369	$24,376	$25,541	$26,241	$27,027
TOTAL	**$504,279**	**$511,870**	**$576,830**	**$625,867**	**$532,455**

Methodology Used in Determining Prices Charged to Affiliates

The services HCHI provide to Haldimand County are charged on a cost-based price plus mark-ups to cover overheads as follows:

- Material – Actual cost plus 16% Burden
- Labour – Actual hourly labour times wage rate plus a 50% Burden
- Trucks – Actual hourly usage times unit rate (calculated based on all costs associated with each truck)
- Administrative – 10% Burden charged on entire invoice before GST

The cost sharing services charged to Haldimand County are per agreements put into place at the time each particular non-affiliate third party service is required and is based on the percentage of the service to be allocated to the each party.

The services provided to each of Haldimand County Energy Inc. ("HCEI") and Haldimand County Utilities Inc. ("HCUI") is also charged at a cost-based price plus a mark-up to labour and truck as noted above. Management and Administrative Salaries are charged out at 1 day per month plus the 50% burden; Billing and Collecting Labour on account of sentinel lights is charged out at $0.25 per sentinel light rental; sentinel light maintenance costs are directly allocated to HCEI for every labour and truck hour worked, and material issued plus applicable burdens; and the water & wastewater billing and collecting administrative fee is calculated as 85% of the fee that HCEI collects from Haldimand County. The fee to the County is calculated using direct and indirect costs related to the service allocated based on the number of water customers to the total water and electric customers.

The methods described above to invoice affiliates for services HCHI provides to them are consistent with that utilized to invoice any other non-affiliate for work performed. Periodic increases in labour, equipment, contractor and material costs are passed on to affiliates and non-affiliates as they occur.

A summary of charges from affiliates for services received in 2006 Actual and 2007 Actual, 2008 Actual together with the projections for the 2009 Bridge Year and 2010 Test Year, are shown in the following Table 8.

TABLE 8
HCHI's CHARGES FROM AFFILIATES

ACTIVITY	2006 Actual	2007 Actual	2008 Actual	2009 Forecast	2010 Forecast
HCHI Charges from Haldimand County:					
Bank Service Charges – Debenture Handling (2007 includes 2001 to 2007)		$5,176	$1,278	$1,272	$1,272
Rental of Garage Facilities (Dunnville Service Yard)	$57,191				
Aerial Photo – Land base for GIS Mapping System	$4,500				
HCHI Charges from HCUI:					
Management Fee	$54,000	$54,000	$54,000	$54,000	$54,000
TOTAL	**$115,691**	**$59,176**	**$55,278**	**$55,272**	**$55,272**

Methodology Used in Determining Prices Charged from Affiliates

The management fee charged to HCHI by HCUI is determined as an annual amount charged monthly. This fee is to account for administration expenses for services provided by the parent company, HCUI's, Board of Directors, for governance and oversight services on behalf of HCHI. An annual amount is also charged from HCUI to HCEI for the same services ($6,000 annual; $500 monthly).

Purchase of Products and Services from Non-Affiliates

Tables 9, 10 and 11 below identify purchased services from non-affiliated vendors for the actual years 2006 (Table 9), 2007 (Table 10), and 2008 (Table 11). The tables disclose expenditures from vendors where the annual total was greater than the materiality threshold of $53,080 in each of the actual years, 2006, 2007 and 2008. The expenditures have been categorized into the departmental groups, Operations, Maintenance, Billing and Collecting, Community Relations, and Administrative.

Table 9
2006 Non-Affiliated Vendor Purchases > $53,080

Department	Vendor Name	Activity	Pricing	Annual Dollars
Operations:	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ	$148,947
Maintenance:	Beswick Tree Service Ltd.	Tree Trimming Services	Tender	$126,751
	Davey Tree Expert Co. of Canada Ltd.	Tree Trimming Services	Tender	$92,160
	D.L. Hannon Inc.	Contractor – Distribution System Work	Tender	$145,093
Billing & Collecting:	Canada Post	Postage & Bulk Mailing Costs	Market Price	$150,663
	ENERConnect Inc. (new vendor July/06) Peterborough Utilities Services Inc.	Wholesale Settlements Provider	RFQ	$40,397 $30,278
	Olameter Inc.	Meter Reading Services	RFQ	$373,761
Community Relations:	None above materiality threshold			
Administrative:	Aegisys 1468625 Ontario Ltd.	IT Services	RFQ	$54,478

	MEARIE Management Inc.	Employee Benefit Provider	RFQ	$195,996
	Millard, Rouse and Rosebrugh	Auditing Services	Retained	$69,141
	Ontario Energy Board	Regulatory Fees & Cost Awards	Regulated	$77,149
	The MEARIE Group	Insurance and Training Fees	Contract	$59,370

Table 10
2007 Non-Affiliated Vendor Purchases > $53,080

Department	**Vendor Name**	**Activity**	**Pricing**	**Annual Dollars**
Operations:	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2006)	$207,865
Maintenance:	Beswick Tree Service Ltd.	Tree Trimming Services	Tender	$309,503
	Davey Tree Expert Co. of Canada Ltd.	Tree Trimming Services	Tender	$290,017
	D.L. Hannon Inc.	Contractor – Distribution System Work	Tender (2006)	$350,397
	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2006)	$119,379
Billing & Collecting:	Canada Post	Postage & Bulk Mailing Costs	Market Price	$144,000
	Olameter Inc.	Meter Reading Services	RFQ	$408,916
Community Relations:	None above materiality threshold			
Administrative:	Aegisys 1468625 Ontario Ltd.	IT Services – Network	RFQ	$54,661

	Harris Computer Systems	IT Services – Billing System	RFQ	$68,855
	MEARIE Management Inc.	Employee Benefit Provider	RFQ	$213,076
	Ontario Energy Board	Regulatory Fees & Cost Awards	Regulated	$66,968

Table 11
2008 Non-Affiliated Vendor Purchases > $53,080

Department	**Vendor Name**	**Activity**	**Pricing**	**Annual Dollars**
Operations:	AESI-Acumen Engineered Solutions	Contractor – Engineering Work	RFQ	$72,556
	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2006)	$96,395
Maintenance:	AEON Egmond Ltd.	Distribution Station (ESA Ph. I & II) and Remediation Work	RFQ & Direct Quote	$109,379
	D.L. Hannon Inc.	Contractor – Distribution System Work	Tender (2006)	$343,358
	Beswick Tree Service Ltd.	Tree Trimming Services	Tender	$54,082
	Ontario Line Clearing & Tree Service Ltd.	Tree Trimming Services	Tender	$480,344
	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2006)	$87,725
Billing & Collecting:	Canada Post	Postage & Bulk Mailing Costs	Market Price	$144,000
	Olameter Inc.	Meter Reading Services	RFQ	$392,266

	Peterborough Utilities Services Inc.	Wholesale Settlements Provider	RFQ	$57,316
Community Relations:	None above materiality threshold			
Administrative:	MEARIE Management Inc.	Employee Benefit Provider	RFQ	$178,187
	Ontario Energy Board	Regulatory Fees & Cost Awards	Regulated	$76,815

Tables 12 and 13 forecast purchased services from non-affiliated vendors for the 2009 Bridge year (Table 12), and the 2010 Test year (Table 13). The tables disclose expenditures from vendors where the annual total was forecasted to be greater than the materiality threshold of $53,354 in the bridge year and test year. The expenditures have been categorized into the departmental groups, Operations, Maintenance, Billing & Collecting, Community Relations, and Administrative.

Table 12
2009 Non-Affiliated Vendor Purchases > $53,080

Department	**Vendor Name**	**Activity**	**Pricing**	**Forecasted Dollars**
Operations:	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2009 contract with option to extend to 2010 & 2011)	$65,130
Maintenance:	Black & McDonald Ltd.	Contractor – Distribution System Work	Tender (2009 contract with option to extend to 2010 & 2011)	$120,000
	Beswick Tree Service Ltd. Davey Tree Expert Co. of Canada Ltd. Oakhill Tree Service Ltd.	Tree Trimming Services	Tender	$546,305

	D.L. Hannon Inc.	Contractor – Distribution System Work	RFQ (Extension of previous contract 2006 – 2008)	$182,213
	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2009 contract with option to extend to 2010 & 2011)	$150,148
Billing & Collecting:	Canada Post	Postage & Bulk Mailing Costs	Market Price	$158,760
	Harris Computer Systems	IT Services – Billing System	RFQ	$85,188
	Olameter Inc.	Meter Reading Services	RFQ	$400,568
	Peterborough Utilities Services Inc.	Wholesale Settlements Provider	RFQ	$55,178
Community Relations:	None above materiality threshold			
Administrative:	MEARIE Management Inc.	Employee Benefit Provider	RFQ	$207,802
	Millard, Rouse and Rosebrugh	Auditing Services	RFQ	$64,203
	Ontario Energy Board	Regulatory Fees & Cost Awards	Regulated	$76,096

Table 13
2010 Non-Affiliated Vendor Purchases > $53,080

Department	**Vendor Name**	**Activity**	**Pricing**	**Forecasted Dollars**
Operations:	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2009)	$65,857
Maintenance:	Black & McDonald Ltd.	Contractor – Distribution System Work	Tender (2009)	$123,600

	Utility Scanning Solutions	Contractor – Distribution System Work	RFQ (2009)	$124,794
	Vendor Unknown	Distribution Station (Nanticoke) Remediation Work	RFQ (Future)	$77,255
	Vendor Unknown	Tree Trimming Services	Tender (Future)	$536,872
Billing & Collecting:	Canada Post	Postage & Bulk Mailing Costs	Market Price	$164,640
	Harris Computer Systems	IT Services – Billing System	RFQ	$93,197
	Olameter Inc.	Meter Reading Services	RFQ	$421,569
	Peterborough Utilities Services Inc.	Wholesale Settlements Provider	RFQ	$56,368
Community Relations:	None above materiality threshold			
Administrative:	Corporation of Haldimand County	Municipal Property Taxes	MPAC & Municipal Assessments	$53,447
	MEARIE Management Inc.	Employee Benefit Provider	RFQ	$225,484
	Millard, Rouse and Rosebrugh	Auditing Services	RFQ	$66,084
	Ontario Energy Board	Regulatory Fees & Cost Awards	Regulated	$80,428

Methodology Used in Determining Non-Affiliated Vendors

HCHI purchases many services from non-affiliated vendors. Some of these vendors are determined through a tendering process and some are solely based on market price or regulated price. HCHI does not have control over the regulated pricing structures or the market prices, such as for the cost of postage.

However, for the majority of the balance of vendor services, HCHI generally purchases services utilizing a competitive bidding process. This process is used for contracts expected to exceed $50,000 and those services below this amount where the marketplace has multiple vendors. The instruments used to procure services ranges from formal tenders, request for quotations (RFQ's), and requests for proposals ("RFP") and quotations (RFPQ's). HCHI has a mature base template for all of the instruments noted and this documentation includes detailed requirements and descriptions as follows:

- Project/Service Overview
- Procurement Process
- Contractor Information Requirements
- HCHI's Business Process Requirements
- Terms and Conditions

The template is adjusted to include elements which are appropriate for the service being procured. Most contracts are for one year and a number of contracts have provisions to extend the contract by up to two more years. In all cases the bids are measured against the information requested in the instrument taking into consideration the cost. Generally, the lowest bid meeting the requirements of the instrument is selected.

EMPLOYEE COMPLEMENT, BENEFITS AND COMPENSATION

Salaries and Wages

HCHI's unionized staff is represented by the Local Union 636 of the International Brotherhood of Electrical Workers ("IBEW Local 636"). A formal set of contract negotiations was recently conducted and resulted in a new four year collective agreement for the period April 1, 2009 to March 31, 2013. The settlement included annual wage cost increases of approximately 2.5% per year beginning in 2009 and improvements to the benefits package. HCHI's wage rates are competitive with other LDCs in its area.

Similarly, the non-union staff was also approved for the same annual wage increase as union employees effective April 1, 2009. The annual rates of increase are as follows:

	Year 1	Year 2	Year 3	Year 4
April 1	2%	2%	2%	3%
October 1	1%	1%	1%	

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation, sick time credits, employee tuition reimbursement, and a company-sponsored retirement plan. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and non-union employees.

OMERS Pension Expense

HCHI's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"), a defined benefit pension plan for employees.

Employee Compensation and Benefits

The following Table 14 summarizes HCHI's employee complement, compensation and benefits including the OMER's pension costs. An allocation has been completed at the bottom of the table to show how many dollars of the total employee compensation and benefits is charged to OM&A versus being capitalized.

Table 14
Employee Compensation and Benefits

	2006 Board Approved (2004)	Historical Year (2006)	Historical Year (2007)	Historical Year (2008)	Bridge Year (2009)	Test Year (2010)
Number of Employees (FTEs including Part-Time)						
Executive	8	9	9	9	9	9
Management	8	10	9	9	9	9
Non-Union	3	3	3	3	3	3
Union	30	30	33	33	33	33
Total	49	52	54	54	54	54
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union						
Total						
Total Salary and Wages						
Executive	178,869.66	186,383.62	189,813.43	201,041.81	197,112.69	201,753.80
Management	601,771.38	719,618.75	726,558.77	723,740.84	742,536.34	765,189.20
Non-Union	149,133.75	156,087.59	156,467.28	175,347.77	176,382.27	181,759.25
Union	1,441,340.58	1,564,340.40	1,753,908.13	1,988,734.64	2,037,364.41	2,116,610.30
Total	2,371,115.37	2,626,430.36	2,826,747.61	3,088,865.06	3,153,395.71	3,265,312.55
Total Benefits						
Executive	4,824.33	5,254.96	5,301.03	4,805.83	5,270.67	5,641.10
Management	81,263.20	105,637.78	107,422.30	92,513.17	105,100.42	111,092.32
Non-Union	20,015.78	24,100.16	24,951.27	26,738.54	29,825.07	31,510.16
Union	179,407.92	194,492.75	230,854.15	234,517.56	266,072.68	289,533.51
Total	285,511.23	329,485.65	368,528.75	358,575.10	406,268.84	437,777.09
Total Compensation (Salary, Wages, & Benefits)						
Executive	183,693.99	191,638.58	195,114.46	205,847.64	202,383.36	207,394.90
Management	683,034.58	825,256.53	833,981.07	816,254.01	847,636.76	876,281.52
Non-Union	169,149.53	180,187.75	181,418.55	202,086.31	206,207.34	213,269.41
Union	1,620,748.50	1,758,833.15	1,984,762.28	2,223,252.20	2,303,437.09	2,406,143.81
Total	2,656,626.60	2,955,916.01	3,195,276.36	3,447,440.16	3,559,664.55	3,703,089.64
Compensation - Average Yearly Base Wages						
Executive	22,092.24	20,709.29	21,090.38	21,881.91	21,901.41	22,417.09
Management	71,411.88	69,190.84	78,967.46	78,087.43	80,597.66	83,056.35
Non-Union	48,084.64	50,733.37	50,889.54	56,436.85	57,940.37	59,706.62
Union	43,582.68	46,158.52	46,662.35	54,034.38	54,600.44	56,647.29
Total	185,171.44	186,792.02	197,609.73	210,440.57	215,039.88	221,827.35
Compensation - Average Yearly Overtime						
Executive	226.47	-	-	456.07	-	-
Management	5,079.39	2,771.03	1,761.29	2,328.22	1,906.38	1,964.67
Non-Union	1,626.61	1,295.83	1,266.22	2,012.41	853.72	879.80
Union	6,779.82	5,986.16	6,715.77	7,185.51	7,137.88	7,492.41
Total	13,712.29	10,053.02	9,743.28	11,982.21	9,897.98	10,336.88
Compensation - Average Yearly Incentive Pay						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Benefits						
Executive	689.44	583.88	589.00	533.98	585.63	626.79
Management	9,029.24	10,563.78	11,935.81	10,279.24	11,677.82	12,343.59
Non-Union	6,671.93	8,033.39	8,317.09	8,912.85	9,941.69	10,503.39
Union	6,801.43	6,483.09	6,995.58	7,106.59	8,062.81	8,773.74
Total	23,192.04	25,664.14	27,837.48	26,832.66	30,267.95	32,247.51
Total Compensation	2,656,626.60	2,955,916.01	3,195,276.36	3,447,440.16	3,559,664.55	3,703,089.64
Total Compensation Charged to OM&A	2,274,869.36	2,561,596.81	2,824,304.77	3,038,229.01	3,129,301.11	3,255,386.10
Total Compensation Capitalized	381,757.24	394,319.20	370,971.59	409,211.15	430,363.44	447,703.54

Changes In Workforce Year Over Year

The preceding Table 14 shows HCHI's FTE headcount for 2006 Board Approved (49), 2006 Actual (52), 2007 Actual (54), 2008 Actual (54), 2009 Bridge Year (54), and 2010 Test Year (54). This headcount includes HCHI's Board of Directors, 8 directors in total, within in the "Executive" line of the table.

2006 Actual versus 2006 Board Approved

The FTE employees increased from 49 to 52 in the 2006 actual year. The FTE headcount for the 2006 Board Approved is the 2004 actual year headcount. Three new positions were created between the years 2004 to 2006, including an Accounting Supervisor, Customer Care Systems Supervisor, and an additional Engineering Technician position. The two supervisory positions are included in the "Management" category in Table 14 and the Engineering Technician is included in the "Union" category. The entry level Engineering Technician was hired in order to train as a replacement for the Technical Services Representative who would be retiring in 2007. The two new supervisory positions were created when the need was identified for the additional staffing to accommodate the increased workloads in the Finance and Customer Service Departments as well to keep up-to-date with the many additional regulatory requirements and changes.

The annual wage rate increases from 2004 (2006 Board Approved) to 2006 actual year as per the Union negotiated contract were 3% January 1, 2005 and in 2006, 2% January 1 and 2% July 1. Non-union employees were also approved for the same annual wage increases.

2007 Actual versus 2006 Actual

The FTE employees increased from 52 to 54 in 2007. The net change of two FTE's is a combination of the addition of one Apprentice Lineperson, the creation of two new positions, an IT Technician and a Lines Clerk, and the elimination of one Lineperson

Supervisor position. The addition of the one Lineperson was to reduce third party contractor costs in order to complete larger projects in a more cost effective manner and to enable HCHI to respond to trouble calls without reducing the efficiency of completing larger projects. With the vacancy of a Lineperson Supervisory position, when one employee left HCHI to pursue their career elsewhere, the need was recognized for an administrative position to assist in the Operations Department versus a second supervisor, and hence the creation of the Lines Clerk position. The IT Technician position was created to reduce external IT costs by performing certain IT activities internally.

The annual union and non-union wage increases for the year 2007 were 3% April 1 and 2% July 1.

2008 Actual versus 2007 Actual

In 2008 the FTE complement did not change from 54 from the 2007 actual year.

The annual union and non-union wage increase for the year 2008 was 4% effective April 1.

2009 Bridge Year versus 2008 Actual

In the 2009 Bridge year the FTE complement is not forecast to change from 54 in the 2008 actual year; that is no additions or deletions are planned.

The annual union and non-union wage increase for the 2009 Bridge year was negotiated in the 4-year union contract of 2% April 1 and 1% October 1.

2010 Test Year versus 2009 Bridge Year

The 2010 Test year does not have any additions or deletions with the FTE complement remaining at 54.

The annual union and non-union wage increase for the 2010 Test year was negotiated in the 4-year union contract at 2% effective April 1, 2010 and 1% effective October 1, 2010.

AMORTIZATION OF CAPITAL ASSETS

Amortization of capital assets is calculated as follows:

- HCHI uses the pooling of assets for all Distribution System capital assets. General Plant capital assets are recorded on an individual basis;
- Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:
- Amortization on capital additions during the current year commences in the month that the asset is acquired;
- Amortization rates are in line with the rates set out in the OEB's APH; and
- HCHI does not have a formalized amortization policy outlining the points above.

The following outlines the amortization rates used by HCHI for each asset group as defined in the Board's guidelines on amortization / depreciation rates (Appendix B of the 2006 Electricity Distribution Rate Handbook).

USoA Account	Asset Type	Life-Years Amortized
1820	Distribution Station Equipment	30 Years
1830, 1835, 1840,1845,1850, 1855, &1860	Distribution System Plant	25 Years
1905	Land	Non-Amortizable
1906	Land Rights	50 Years
1908	Buildings & Fixtures	50 Years
1915	General Office Equipment	10 Years
1920	Computer Equipment - Hardware	5 Years
1925	Computer Equipment – Software	5 Years

USoA Account	Asset Type	Life-Years Amortized
1930	Rolling Stock & Equipment	8 Years
1940	Tools, Shop, and Garage Equipment	10 Years
1955	Communication Equipment	5 Years

Details of HCHI's amortization by asset group are provided in Table 15 below, filed as per the "Filing Guidelines" (*Appendix 2-N*). The Fixed Asset Continuity Schedules in Exhibit 2, Tab 2, Schedule 1 also detail the accumulated amortization for each of HCHI's asset groups.

Table 15
Accumulated Amortization

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Bridge ($)	Variance from 2008 Actual	2010 Test ($)	Variance from 2009 Bridge
Land and Buildings											
1805-Land											
1806-Land Rights											
1808-Buildings and Fixtures											
1905-Land											
1906-Land Rights	82,946	135,455	52,509	156,175	20,721	176,952	20,777	194,727	17,775	212,502	17,775
1810-Leasehold Improvements											
Sub-Total-Land and Buildings	82,946	135,455	52,509	156,175	20,721	176,952	20,777	194,727	17,775	212,502	17,775
TS Primary Above 50											
1815-Transformer Station Equipment - Normally Primary above 50 kV											
Sub-Total-TS Primary Above 50											
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	127,691	180,549	52,858	197,352	16,803	211,925	14,573	232,918	20,993	253,911	20,994
Sub-Total-DS	127,691	180,549	52,858	197,352	16,803	211,925	14,573	232,918	20,993	253,911	20,994
Poles and Wires											
1830-Poles, Towers and Fixtures	2,674,557	4,482,621	1,808,064	5,181,439	698,817	5,924,112	742,673	6,717,138	793,026	7,539,220	822,082
1835-Overhead Conductors and Devices	913,865	1,639,342	725,477	1,941,588	302,246	2,285,586	343,998	2,701,339	415,753	3,140,010	438,670
1840-Underground Conduit	16,431	39,507	23,076	49,690	10,184	63,472	13,782	87,407	23,935	125,939	38,532
1845-Underground Conductors and Devices	1,062,713	1,813,424	750,711	2,101,006	287,581	2,401,999	300,994	2,708,694	306,695	3,023,969	315,275
Sub-Total-Poles and Wires	4,667,566	7,974,894	3,307,328	9,273,722	1,298,828	10,675,170	1,401,447	12,214,579	1,539,409	13,829,138	1,614,559
Line Transformers											
1850-Line Transformers	1,270,175	2,202,791	932,616	2,572,465	369,674	2,921,665	349,200	3,351,731	430,066	3,802,412	450,681
Sub-Total-Line Transformers	1,270,175	2,202,791	932,616	2,572,465	369,674	2,921,665	349,200	3,351,731	430,066	3,802,412	450,681
Services and Meters											
1855-Services	124,849	284,554	159,705	361,405	76,851	445,293	83,887	538,582	93,289	639,711	101,129
1860-Meters	373,201	640,325	267,124	745,353	105,028	850,198	104,845	960,978	110,780	1,075,269	114,290
Sub-Total-Services and Meters	498,050	924,879	426,829	1,106,759	181,879	1,295,491	188,733	1,499,560	204,069	1,714,980	215,419
General Plant											
1908-Buildings and Fixtures	98,974	181,661	82,687	223,064	41,403	270,056	46,992	318,071	48,015	366,086	48,015
1910-Leasehold Improvements											
Sub-Total-General Plant	98,974	181,661	82,687	223,064	41,403	270,056	46,992	318,071	48,015	366,086	48,015
IT Assets											
1920-Computer Equipment - Hardware	138,423	285,238	146,815	311,732	26,493	361,839	50,107	427,821	65,982	478,620	50,799
1921-Computer Equipment											
1921-Computer Equipment - Hardware post March 22, 2005											
1925-Computer Software	159,400	433,553	274,153	603,454	169,901	805,120	201,666	1,155,006	349,886	1,543,784	388,778
Sub-Total-IT Assets	297,823	718,791	420,968	915,186	196,395	1,166,959	251,773	1,582,827	415,868	2,022,404	439,578
Equipment											
1915-Office Furniture and Equipment	60,977	115,420	54,443	139,324	23,904	142,611	3,287	175,453	32,842	206,213	30,760
1930-Transportation Equipment	415,059	670,358	255,299	777,195	106,837	841,028	63,833	1,022,873	181,845	1,200,243	177,370
1935-Stores Equipment											
1940-Tools, Shop and Garage Equipment	91,010	170,114	79,104	206,071	35,957	249,235	43,164	278,135	28,900	307,222	29,086
1945-Measurement and Testing Equipment											
1950-Power Operated Equipment											
1955-Communication Equipment	29,272	55,860	26,588	61,337	5,477	65,202	3,865	66,282	1,080	66,282	
1960-Miscellaneous Equipment											
Sub-Total-Equipment	596,318	1,011,752	415,434	1,183,927	172,175	1,298,076	114,149	1,542,743	244,667	1,779,960	237,217
Other Distribution Assets											
1825-Storage Battery Equipment											
1970-Load Management Controls - Customer Premises											
1975-Load Management Controls - Utility Premises											
1980-System Supervisory Equipment											
1985-Sentinel Lighting Rental Units											
1990-Other Tangible Property											
1995-Contributions and Grants - Credit		(241,907)	(241,907)	(326,089)	(84,182)	(427,196)	(101,107)	(534,082)	(106,886)	(646,232)	(112,150)
1996-Hydro One S/S Contribution											
Sub-Total-Other Distribution Assets		(241,907)	(241,907)	(326,089)	(84,182)	(427,196)	(101,107)	(534,082)	(106,886)	(646,232)	(112,150)
ACCUMULATED AMORTIZATION TOTAL	7,639,543	13,088,866	5,449,323	15,302,560	2,213,695	17,589,099	2,286,538	20,403,075	2,813,976	23,335,161	2,932,087

TAXES (PILS, CAPITAL TAX and PROPERTY TAXES)

Under Section 93 of the *Electricity Act, 1998*, as amended, Haldimand County Hydro makes payments in lieu ("PILS") of corporate taxes. These payments are calculated in accordance with the rules for computing taxable income, 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.

Detailed PILS/Tax Calculations

HCHI is requesting a PILS/Tax Provision in the amount of $741,703 for the 2010 Test Year. This includes combined Federal and Ontario corporate income tax (grossed-up) in the amount of $722,880 and Ontario capital tax (not grossed-up) in the amount of $18,823.

HCHI has calculated the 2010 Test Year PILS/Tax Provision in accordance with the Board's tax methodology utilizing the OEB's Tax Model provided with the OEB's *Chapter 2 of the Filing Requirements for Transmission and Distribution Rate Applications*, as updated May 27, 2009. HCHI has relied upon the tax rates and exemptions and capital cost allowance rates as provided in the OEB's Tax Model. A summary of the tax rates and exemptions for 2008, 2009 and 2010 (as of March 26, 2009) is set out in the following Table 16. The details of the undepreciated capital cost ("UCC"), capital cost allowance ("CCA") and the cumulative eligible capital ("CEC") amounts for the 2009 Bridge Year and 2010 Test Year are provided as continuity schedules in the following Table 17.

Taxable income calculations for each of the 2006 Board-approved, 2008 Actual, 2009 Bridge Year and 2010 Test Year are provided in the following Table 18. The resulting PILs/Tax Provision calculation for each of these years is provided in the following Table 19. The 2008 Actual amounts are as reported in the Federal "T2 Corporation Income Tax Return" and Ontario "CT23 Corporations Tax and Annual Return" as filed for the year ended December 31, 2008 – copies of which are provided in **Appendix A**. The

income tax provision reported in the 2008 audited financial statements (Exhibit 1 – Tab 3 – Appendix I) is based on an estimate and will differ from the payable amounts per the income tax returns. The difference between the estimated provision and actual payable will be reflected in the 2009 audited financial statements.

Table 16
Tax Rates and Exemptions

Federal & Provincial Tax Rates **As of March 26, 2009**	**Notes**	**Effective January 1, 2008**	**Effective January 1, 2009**	**Effective January 1, 2010**
Federal income tax				
General corporate rate	**1**	38.00%	38.00%	38.00%
Federal tax abatement	**2**	-10.00%	-10.00%	-10.00%
Adjusted federal rate	**3**	28.00%	28.00%	28.00%
Surtax (4% of line 3)	**4**	0.00%	0.00%	0.00%
		28.00%	28.00%	28.00%
Rate reduction		-8.50%	-9.00%	-10.00%
		19.50%	**19.00%**	**18.00%**
Ontario income tax		**14.00%**	**14.00%**	**13.00%**
Combined federal and Ontario		33.50%	33.00%	31.00%
Ontario Capital Tax				
Capital deduction		15,000,000	15,000,000	15,000,000
Capital tax rate		**0.225%**	**0.225%**	**0.075%**
OCT will be eliminated on July 1, 2010 but tax will be prorated for the first 6 months in 2010.				

NOTES:

1. Based on the federal government's October 30, 2007 Economic Statement. Bill C-28 received Royal Assent on December 14, 2007.

2. Ontario Economic Statement of December 13, 2007 became Bill 44 and received Royal Assent on May 14, 2008. Capital tax rate changes and small business deduction income thresholds made retroactive to January 1, 2007.

3. Federal Budget of January 27, 2009 The federal small business limit was increased from from $400,000 to $500,000 on January 1, 2009.

4. Federal Budget of March 26, 2009 The provincial corporate tax rate was reduced.

Table 17
UCC, CCA and CEC Continuity Schedules

2009 BRIDGE YEAR

Class	Class Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Rule	1/2 Year Rule {1/2 Addn's Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 25,811,722	$ -	$ -	$ 25,811,722	$ -	$ 25,811,722	4%	$ 1,032,469	$ 24,779,253
8	General Office/Stores Equip	$ 787,784	$ 231,364	$ -	$ 1,019,148	$ 115,682	$ 903,466	20%	$ 180,693	$ 838,455
10	Computer Hardware/ Vehicles	$ 295,110	$ 586,656	$ -	$ 881,766	$ 293,328	$ 588,438	30%	$ 176,531	$ 705,235
12	Computer Software	$ 208,192	$ 242,605	$ -	$ 450,797	$ 121,303	$ 329,495	100%	$ 329,495	$ 121,303
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 67,985	$ -	$ -	$ 67,985	$ -	$ 67,985	8%	$ 5,439	$ 62,546
45	Computers & Systems Software acq'd post Mar 22/04	$ 36,345	$ -	$ -	$ 36,345	$ -	$ 36,345	45%	$ 16,355	$ 19,990
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 401	$ -	$ -	$ 401	$ -	$ 401	30%	$ 120	$ 281
47	Distribution System - post February 2005	$ 7,911,618	$ 3,306,497	$ -	$ 11,218,115	$ 1,653,249	$ 9,564,867	8%	$ 765,189	$ 10,452,926
50	Data Network Infrastructure Equipment - post Mar 2007	$ 44,654	$ 42,542	$ -	$ 87,196	$ 21,271	$ 65,925	55%	$ 36,259	$ 50,937
1	March 2007 Buildings	$ 81,263	$ 19,435	$ -	$ 100,698	$ 9,718	$ 90,981	6%	$ 5,459	$ 95,239
	UCC and CCA - TOTAL	**$ 35,245,074**	**$ 4,429,099**	**$ -**	**$ 39,674,173**	**$ 2,214,550**	**$ 37,459,624**		**$ 2,548,009**	**$ 37,126,164**

CEC	**Cumulative Eligible Capital**	**$ 296,681**	**$ -**	**$ -**	**$ 296,681**	**$ -**	**$ 296,681**	7%	**$ 20,768**	**$ 275,913**

Table 17 (continued)
UCC, CCA and CEC Continuity Schedules

2010 TEST YEAR

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Rule	1/2 Year Rule {1/2 Addn's Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 24,779,253	$ -	$ -	$ 24,779,253	$ -	$ 24,779,253	4%	$ 991,170	$ 23,788,083
8	General Office/Stores Equip	$ 838,455	$ 232,494	$ -	$ 1,070,949	$ 116,247	$ 954,702	20%	$ 190,940	$ 880,008
10	Computer Hardware/ Vehicles	$ 705,235	$ 273,600	$ -	$ 978,835	$ 136,800	$ 842,035	30%	$ 252,610	$ 726,224
12	Computer Software	$ 121,303	$ 241,243	$ -	$ 362,546	$ 120,622	$ 241,924	100%	$ 241,924	$ 120,622
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 62,546	$ -	$ -	$ 62,546	$ -	$ 62,546	8%	$ 5,004	$ 57,543
45	Computers & Systems Software acq'd post Mar 22/04	$ 19,990	$ -	$ -	$ 19,990	$ -	$ 19,990	45%	$ 8,995	$ 10,994
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 281	$ -	$ -	$ 281	$ -	$ 281	30%	$ 84	$ 196
47	Distribution System - post February 2005	$ 10,452,926	$ 2,546,288	$ -	$ 12,999,214	$ 1,273,144	$ 11,726,070	8%	$ 938,086	$ 12,061,128
50	Data Network Infrastructure Equipment - post Mar 2007	$ 50,937	$ 18,676	$ -	$ 69,613	$ 9,338	$ 60,275	55%	$ 33,151	$ 36,462
1	March 2007 Buildings	$ 95,239	$ -	$ -	$ 95,239	$ -	$ 95,239	6%	$ 5,714	$ 89,525
	UCC and CCA - TOTAL	**$ 37,126,164**	**$ 3,312,301**	**$ -**	**$ 40,438,465**	**$ 1,656,151**	**$ 38,782,314**		**$ 2,667,679**	**$ 37,770,785**
CEC	**Cumulative Eligible Capital**	**$ 275,913**	**$ -**	**$ -**	**$ 275,913**	**$ -**	**$ 275,913**	**7%**	**$ 19,314**	**$ 256,599**

Table 18
Taxable Income

	Historic	Historic	Bridge	Test
	2006 Board Approved	2008 "Actual"	2009 Forecast	2010 Forecast
Income Before PILs/Taxes	**$ 1,558,682**	**$ 3,285,446**	**$ 1,418,970**	**$ 1,284,710**
Additions:				
Amortization of tangible assets	$ 2,139,317	$ 2,442,300	$ 2,813,977	$ 2,932,087
Loss on disposal of assets	$ 3,156	$ -	$ -	$ -
Taxable Capital Gains	$ 8,980	$ 6,782	$ -	$ -
Non-deductible meals and entertainment expense	$ -	$ 9,093	$ 9,366	$ 9,647
Financing fees deducted in books	$ -	$ 9,706	$ 9,706	$ 3,235
Prior year apprenticeship job creation tax credit	$ 2,659	$ 2,000	$ 6,000	$ 6,000
Ontario Specified Tax Credits	$ -	$ 19,243	$ 14,726	$ 15,000
Regulatory Assets - Opening Balance	$ 3,954,667		$ 728,070	$ 4,457,505
Total Additions	**$ 6,108,779**	**$ 2,489,124**	**$ 3,581,845**	**$ 7,423,473**
Deductions:				
Gain on disposal of assets per financial statements	$ 23,474	$ 23,778	$ -	$ -
Capital cost allowance from Schedule 8	$ 1,538,446	$ 2,235,888	$ 2,548,009	$ 2,667,679
Cumulative eligible capital deduction from Schedule 10 CEC	$ 27,762	$ 22,331	$ 20,768	$ 19,314
Regulatory Assets - Closing Balance	$ 1,924,076	$ 728,070	$ 4,457,505	$ 4,344,457
Regulatory Liabilities - Opening Balance	$ -	$ 480,776	$ -	$ -
Total Deductions	**$ 3,513,758**	**$ 3,490,843**	**$ 7,026,282**	**$ 7,031,450**
REGULATORY TAXABLE INCOME	**$ 4,153,703**	**$ 2,283,727**	**$ (2,025,467)**	**$ 1,676,733**

Table 19
PILS/Tax Provision Calculations

	HISTORIC		HISTORIC		BRIDGE YEAR		TEST YEAR	
	2006 Board Approved		2008 "Actual"		2009 Forecast		2010 Forecast	
Taxable Income		**$ 4,153,703**		**$ 2,283,727**		**$ (2,025,467)**		**$ 1,676,733**
Combined Tax Rate								
Ontario Tax Rate	22.12%		13.96%		14.00%		13.00%	
Federal tax rate	14.00%		19.55%		19.00%		18.00%	
Combined tax rate	36.12%		33.50%		33.00%		31.00%	
Total Income Taxes		$ 1,500,318		$ 765,127		$ (668,404)		$ 519,787
Tax Credits								
Investment Tax Credits		$ -		$ 6,000		$ 6,000		$ 6,000
Miscellaneous Tax Credits		$ 2,659		$ 19,243		$ 14,726		$ 15,000
Total Tax Credits		$ 2,659		$ 25,243		$ 20,726		$ 21,000
Income Tax Provision		$ 1,497,659		$ 739,884		$ (689,130)		$ 498,787
Income Tax Provision Gross Up	63.88%	$ 846,829			67.00%	$ (339,422)	69.00%	$ 224,093
Income Tax (grossed-up)		**$ 2,344,487**		**$ 739,884**		**$ (1,028,552)**		**$ 722,880**
Ontario Capital Tax (not grossed-up)		**$ 88,962**		**$ 60,190**		**$ 54,021**		**$ 18,823**
PILS/TAX PROVISION FOR YEAR		**$ 2,433,449**		**$ 800,074**		**$ (974,532)**		**$ 741,703**
Ontario Capital Tax								
Rate Base		$ 39,653,961		$ 41,581,173		$ 39,009,183		$ 40,097,055
Less: Exemption		$ 10,000,000		$ 14,830,262		$ 15,000,000		$ 15,000,000
Taxable Capital		$ 29,653,961		$ 26,750,911		$ 24,009,183		$ 25,097,055
OCT Rate	0.300%		0.225%		0.225%		0.075%	
Ontario Capital Tax		$ 88,962		$ 60,190		$ 54,021		$ 18,823

Property Taxes

Property taxes, actual paid in 2008, and forecast to be paid in the 2009 Bridge Year and the 2010 Test Year are set out in the following Table 20.

Table 20
Property Taxes

	2008 Actual Year	2009 Bridge Year	2010 Test Year
Property Taxes (Paid to Municipality)			
Service Centre - 1 Greendale Drive, Caledonia	$ 37,151	$ 39,996	$ 41,161
Selkirk North Distribution Station - 71 Selkirk St., Caledonia	$ 1,585	$ 887	$ 913
Selkirk South Distribution Station - 112 Selkirk St., Caledonia	$ 4,069	$ 1,878	$ 1,932
John Distribution Station - 15 John St., Hagersville	$ 1,559	$ 512	$ 526
Forest Distribution Station - 134 Forest St. E., Dunnville	$ 959	$ 1,529	$ 1,574
Nanticoke Distribution Station - Walpole Con E	$ 42	$ 199	$ 204
Jarvis Distribution Station - 1423 Haldimand Road 55	$ 53	$ 238	$ 245
Canfield Distribution Station - 105 Haldimand Hwy #56	$ 1,162	$ 1,299	$ 1,337
Rainham Distribution Station - 0 Haldimand Road 12	$ 32	$ -	$ -
Decewsville Distribution Station - 2283 River Rd	$ 116	$ 327	$ 336
Decewsville Regulating Station - 315 Decewsville Rd	$ 1,902	$ 2,129	$ 2,191
	$ 48,631	$ 48,994	$ 50,419
PILS - Property Taxes (Paid to OEFC)	$ 2,892	$ 2,943	$ 3,028
Total Property Taxes	**$ 51,523**	**$ 51,937**	**$ 53,447**

The changes in property taxes between the 2008 Actual, 2009 Bridge and 2010 Test Years is modest and primarily the result of decreases to certain property assessment values, and increases in municipal property tax rates in the order of 3% annually.

Canada Revenue Agency | Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

CLIENT'S COPY

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), 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, and paragraphs 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. 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 the *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 89075 9814 RC0001

Corporation's name

002 HALDIMAND COUNTY HYDRO INC.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes ☐ 2 No ☒

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** 004 1 Yes ☐ 2 No ☐

Address of head office

Has this address changed since the last time you filed your T2 return? 010 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018)

011 1 GREENDALE DRIVE R. R. #2

012

City: 015 CALEDONIA

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 N3W 2J3

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028)

021 c/o

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 you filed your T2 return? 030 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038)

031 1 GREENDALE DRIVE R. R. #2

032

City: 035 CALEDONIA

Province,territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 N3W 2J3

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 2008-01-01 YYYY MM DD

Tax year-end: 061 2008-12-31 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 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 ☒

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

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
e 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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	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		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? (Yes)	203	X	3
Is the corporation claiming any type of losses? (No)	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
the corporation realized any capital gains or incurred any capital losses during the tax year? (Yes) Sale of Rainham Rd Property	206	X	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) is the corporation claiming the refundable portion of Part I tax?	207	X	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 reserves of any kind?	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? (Yes) Apprenticeship Job Creation	231	X	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 a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
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 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
the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
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	X	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

Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale 2 Retail

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	UTILITY	285	100.000 %
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

corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide date the corporation ceased to be eligible 294 YYYY MM DD

If the corporation's major business activity is construction, did you have any sub-contractors 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	2,283,727	A
Deduct: Charitable donations from Schedule 2	311			
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				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			2,283,727	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
ble income (amount C **plus** amount D)		360	2,283,727	
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)			2,283,727	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 ..... 400 2,276,945 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax ..... 405 2,283,727 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000 x (Number of days in the tax year in 2006 / Number of days in the tax year 366) = ... 1

400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year 366 / 366) = ... 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) ..... 410 400,000 C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 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 400,000 x 415 *** 35,849 / 11,250 D = ... 1,274,631 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 (Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366) x 16 % = 5

Amount A, B, C, or F whichever is the least x (Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year 366 / 366) x 17 % = 6

Amount A, B, C, or F whichever is the least x (Number of days in the tax year after December 31, 2008 / Number of days in the tax year 366) x 17 % = 7

Total of amounts 5, 6, and 7 – enter on line 9 430 G

* 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.

** 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 the previous tax years, the amount to be entered at 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 at 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.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] ..... 435 H

Amount H x (Number of days in the tax year in 2006 / Number of days in the tax year 366) x 5 % = I

Amount H x (Number of days in the tax year in 2007 / Number of days in the tax year 366) x 7 % = J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J ..... 438 K
Enter amount K on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360						2,283,727	A
Amount Z1 from Part 9 of Schedule 27							B
Amount QQ from Part 13 of Schedule 27							C
Taxable resource income from line 435							D
Amount used to calculate the credit union deduction from Schedule 17							E
Amount from line 400, 405, 410, or 425, whichever is the least							F
Aggregate investment income from line 440						6,782	G
Total of amounts B, C, D, E, F, and G					▶	6,782	H
Amount A **minus** amount H (if negative, enter "0")						2,276,945	I
Amount I	2,276,945	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	366	x 7 % =		J
Amount I	2,276,945	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x 8.5 % =	193,540	K
Amount I	2,276,945	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	366	x 9 % =		L
Amount I	2,276,945	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	366	x 10 % =		L1
General tax reduction for Canadian-controlled private corporations – Total of amounts J, K, L, and L1						193,540	M

Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)							N
Amount Z1 from Part 9 of Schedule 27							O
Amount QQ from Part 13 of Schedule 27							P
Taxable resource income from line 435							Q
Amount used to calculate the credit union deduction from Schedule 17							R
Total of amounts O, P, Q, and R					▶		S
Amount N **minus** amount S (if negative, enter "0")							T
Amount T		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	366	x 7 % =		U
Amount T		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x 8.5 % =		V
Amount T		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	366	x 9 % =		W
Amount T		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	366	x 10 % =		W1
General tax reduction – Total of amounts U, V, W, and W1							X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income ..... 440 6,782 x 26 2 / 3 % = ... 1,809 A
from Schedule 7

Foreign non-business income tax credit from line 632 .....

Deduct:

Foreign investment income ..... 445 x 9 1 / 3 % =
from Schedule 7 (if negative, enter "0") ▶ B

Amount A **minus** amount B (if negative, enter "0") ..... 1,809 C

Taxable income from line 360 2,283,727

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least .....

Foreign non-business income tax credit from line 632 ..... x 25 / 9 =

Foreign business income tax credit from line 636 ..... x 3 =

▶

2,283,727

x 26 2 / 3 % = 608,994 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) 440,355

Deduct: Corporate surtax from line 600 .....

Net amount ..... 440,355 ▶ 440,355 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least ..... 450 1,809 F

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 1,809

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

1,809 ▶ 1,809 H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H 485 1,809

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 of Schedule 3 ..... 449,627 x 1 / 3 149,876 I

Refundable dividend tax on hand at the end of the tax year from line 485 above ..... 1,809 J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) 1,809

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . . 550 867,816 A

Corporate surtax calculation

Base amount from line A above 867,816 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) 228,373 2

Investment corporation deduction from line 620 below 3

Federal logging tax credit from line 640 below 4

Federal qualifying environmental trust tax credit from line 648 below 5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360 . . . . . a

28.00 % of taxed capital gains . . . . . b

Part I tax otherwise payable (line A **plus** lines C and D **minus** line F) c

6

Total of lines 2 to 6 . . . . . 228,373 7

Net amount (line 1 **minus** line 7) 639,443 8

Corporate surtax*

Line 8 639,443 x (Number of days in the tax year before January 1, 2008 ____ / Number of days in the tax year 366) x 4 % = 600 ____ B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . . 602 ____ C

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 . . . . . 6,782 i

Taxable income from line 360 2,283,727

duct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . . ____

Net amount . . . . . 2,283,727 ▶ 2,283,727 ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 452 D

Subtotal (**add** lines A, B, C, and D) 868,268 E

Deduct:

Small business deduction from line 430 9

Federal tax abatement 608 228,373

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

Resource deduction from line 438 10

General tax reduction for CCPCs from amount M 638 193,540

General tax reduction from amount X 639

Federal logging tax credit from Schedule 21 640

Federal political contribution tax credit 644

Federal political contributions 646

Federal qualifying environmental trust tax credit 648

Investment tax credit from Schedule 31 . . . . . 652 6,000

Subtotal 427,913 ▶ 427,913 F

Part I tax payable – Line E **minus** line F . . . . . 440,355 G

Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	440,355
Part I.3 tax payable from Schedule 33, 34, or 35	704	
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		440,355

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	440,355 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784	1,809	
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	438,710	
Total credits	890	440,519	440,519 B

Refund code 894 | Overpayment 164 | Balance (line A **minus** line B) -164

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 PAYNE (Last name in block letters) 951 LLOYD (First name in block letters) 954 PRESIDENT (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 further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009-05-22 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation

956 (905) 765-5211 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

Schedule of Instalment Remittances

Name of corporation contact
phone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Total installments for the year	438,710
	Allocated to Provincial component	
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	438,710 **A**
	Total instalments credited to the taxation year per T9	438,710 **B**

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	11,794,054	13,631,229
	Total tangible capital assets	2008	+	53,099,840	48,162,825
	Total accumulated amortization of tangible capital assets	2009	–	18,016,295	15,628,650
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,461,476	22,647
	*Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	48,339,075	46,188,051
Liabilities					
	Total current liabilities	3139	+	9,874,608	6,560,129
	Total long-term liabilities	3450	+	7,860,738	11,965,140
	*Subordinated debt	3460	+	2,249,223	2,108,118
	*Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	19,984,569	20,633,387
areholder equity					
	Total shareholder equity (mandatory field)	3620	+	28,354,506	25,554,664
	Total liabilities and shareholder equity	3640	=	48,339,075	46,188,051
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	8,473,801	5,673,959

* Generic item

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Current Assets

Form Identifier 1599

Account	Description	GIFI		Current year	Prior year
Cash and deposits					
	*Cash and deposits	1000		3,541,338	5,335,328
	Cash and deposits		+	3,541,338	5,335,328
Accounts receivable					
	*Accounts receivable	1060		6,851,010	6,351,027
	Accounts receivable		+	6,851,010	6,351,027
Inventories					
	*Inventories	1120		918,765	1,328,030
	Inventories		+	918,765	1,328,030
Due from/investment in related parties					
	Loans/advances due from related parties	1403			5,089
	Due from/investment in related parties		+		5,089
Other current assets					
	Taxes recoverable/refundable	1483		198,740	549,534
	Prepaid expenses	1484		284,201	62,221
	Other current assets		+	482,941	611,755
	Total current assets	1599	=	11,794,054	13,631,229

* Generic item

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Tangible Capital Assets and Accumulated Amortization

Form Identifier 2008/2009

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
Land							
	*Land	1600	+	139,071			160,824
	Total			139,071			
Buildings							
	*Buildings	1680	+	1,993,907			1,910,131
	*Accumulated amortization of buildings	1681			–	270,056	223,064
	Total			1,993,907		270,056	
Other tangible capital assets							
	*Other tangible capital assets	1900	+	50,966,862			46,091,870
	*Accumulated amortization of other tangible capital assets	1901			–	17,746,239	15,405,586
	Total			50,966,862		17,746,239	
	Total tangible capital assets	2008	=	53,099,840			48,162,825
	Total accumulated amortization of tangible capital assets	2009			=	18,016,295	15,628,650

* Generic item

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Long-term Assets

Form Identifier 2589

Account	Description	GIFI	Current year	Prior year
	Other long-term assets			
	* Other long-term assets	2420	728,070	
	Future (deferred) income taxes	2421	720,465	
	Other deferred items/charges	2424	12,941	22,647
	Other long-term assets	+	1,461,476	22,647
	Total long-term assets	2589 =	1,461,476	22,647

* Generic item

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Current Liabilities

Form identifier 3139

ount	Description	GIFI		Current year	Prior year
Amounts payable and accrued liabilities					
	*Amounts payable and accrued liabilities	2620		5,610,804	4,970,677
	Amounts payable and accrued liabilities		+	5,610,804	4,970,677
Due to related parties					
	*Due to related parties	2860		422,975	368,452
	Due to related parties		+	422,975	368,452
	*Current portion of long-term liability	2920	+	3,840,829	1,221,000
	Total current liabilities	3139	=	9,874,608	6,560,129

* Generic item

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Long-term Liabilities

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	Chartered bank loan	3143		600,000	800,000
	Long-term debt		+	600,000	800,000
	*Bonds and debentures	3210	+	10,665,000	11,486,000
	*Deferred income	3220	+		480,776
Other long-term liabilities					
	*Other long-term liabilities	3320		-3,840,829	-1,221,000
	General provisions/reserves	3325		436,567	419,364
	Other long-term liabilities		+	-3,404,262	-801,636
	Total long-term liabilities	3450	=	7,860,738	11,965,140

* Generic item

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Shareholder Equity

Form identifier 3620

Account	Description	GIFI		Current year	Prior year
	* Common shares	3500	+	17,144,796	17,144,796
	Contributed and other surplus				
	Contributed surplus	3541		2,735,909	2,735,909
	Contributed and other surplus		+	2,735,909	2,735,909
	* Retained earnings/deficit	3600	+	8,473,801	5,673,959
	Total shareholder equity	3620	=	28,354,506	25,554,664

* Generic item

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Retained Earnings/Deficit

Form Identifier 3849

ount	Description	GIFI		Current year	Prior year
	*Retained earnings/deficit – start	3660	+	5,673,959	4,349,078
	*Net income/loss	3680	+	1,993,151	1,729,333
Dividends declared					
	*Dividends declared	3700		449,627	404,452
	Dividends declared		–	449,627	404,452
	*Prior period adjustments	3720	+	1,256,318	
	Retained earnings/deficit – end	3849	=	8,473,801	5,673,959

* Generic item

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

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	+		
	Cost of sales	8518	–		
	Gross profit/loss	8519	=		
	Cost of sales	8518	+		
	Total operating expenses	9367	+	31,211,453	31,934,994
	Total expenses (mandatory field)	9368	=	31,211,453	31,934,994
	Total revenue (mandatory field)	8299	+	34,496,899	34,537,667
	Total expenses (mandatory field)	9368	–	31,211,453	31,934,994
	Net non-farming income	9369	=	3,285,446	2,602,673
ming 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	=	3,285,446	2,602,673
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	–	756,442	873,340
	Deferred income tax provision	9995	–	535,853	
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,993,151	1,729,333

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SCHEDULE 141

NOTES CHECKLIST

›ration's name	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

- 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) for Corporations* 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 preparing or reporting 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 102 to 107 below:

Are any values presented at other than cost? . . . . . 102 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . 103 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [X] 2 No [ ]

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 [X] 2 No [ ]

›es, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . 109 1 Yes [ ] 2 No [X]

NOTICE TO READER

ON THE BASIS OF INFORMATION PROVIDED BY MANAGEMENT, WE HAVE COMPILED THE G.I.F.I.

WE HAVE NOT PERFORMED AN AUDIT OR A REVIEW ENGAGEMENT IN RESPECT OF THIS FINANCIAL INFORMATION AND, ACCORDINGLY, WE EXPRESS NO ASSURANCE THEREON.

READERS ARE CAUTIONED THAT THIS FINANCIAL INFORMATION MAY NOT BE APPROPRIATE FOR THEIR PURPOSES.

MILLARD, ROUSE & ROSEBRUGH LLP
LICENSED PUBLIC ACCOUNTANTS
BRANTFORD, ONTARIO

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

- 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*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements				1,993,151 A
Add:				
Provision for income taxes – current	101	756,442		
Provision for income taxes – deferred	102	535,853		
Amortization of tangible assets	104	2,442,300		
Taxable capital gains from Schedule 6	113	6,782		
Non-deductible meals and entertainment expenses	121	9,093		
Subtotal of additions		3,750,470	▶	3,750,470
Other additions:				
Financing fees deducted in books	216	9,706		
Miscellaneous other additions:				
600 Prior year apprenticeship job creation tax credit	290	2,000		
603.2 Ontario Specified Tax Credits 19,243				
Total 19,243	293	19,243		
Subtotal of other additions	199	30,949	▶	30,949
Total additions	500	3,781,419	▶	3,781,419
Deduct:				
Gain on disposal of assets per financial statements	401	23,778		
Capital cost allowance from Schedule 8	403	2,235,888		
Cumulative eligible capital deduction from Schedule 10	405	22,331		
Subtotal of deductions		2,281,997	▶	2,281,997
Other deductions:				
Miscellaneous other deductions:				
704.1 REG LIABILITY 2007 480,776				
704.2 REG ASSETS 2008 728,070				
Total 1,208,846	394	1,208,846		
Subtotal of other deductions	499	1,208,846	▶	1,208,846
Total deductions	510	3,490,843	▶	3,490,843
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				2,283,727

* For reference purposes only

T2 SCH 1 E (08)

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
ALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return.*
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	Complete if payer corporation is connected: B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
1						
					Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1 Eligible dividends	F2	If payer corporation is not connected, leave these columns blank. G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
1						
Total (enter amount of column F on line 320 of the T2 return)						J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . .

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax 320

Subtotal

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax	330	
Non-capital losses from previous years claimed to reduce Part IV tax	335	
Current-year farm loss claimed to reduce Part IV tax	340	
Farm losses from previous years claimed to reduce Part IV tax	345	

Total losses applied against Part IV tax x 1 / 3 =

Part IV tax payable (enter amount on line 712 of the T2 return) 360

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A Name of connected recipient corporation 400	B Business Number 410	C Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	D Taxable dividends paid to connected corporations 430
1	Haldimand County Utilities	86391 7795 RC0001	2008-12-31	449,627
2				

Note

If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 449,627

Total taxable dividends paid in the taxation year to other than connected corporations 450

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) 460 449,627

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above) 460 449,627

Other dividends paid in the taxation year (total of 510 to 540) . . . . . .

Total dividends paid in the taxation year 500 449,627

Deduct:

Dividends paid out of capital dividend account	510	
Capital gains dividends	520	
Dividends paid on shares described in subsection 129(1.2)	530	
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540	

Subtotal ▶

Total taxable dividends paid in the taxation year for purposes of a dividend refund 449,627

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SCHEDULE 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss, or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act*, if the control of the corporation has been acquired by a person or group of persons.

For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes ☐ 2 No ☒ If *Yes*, attach a statement specifying which properties are subject to such a designation.

Part 1 – Shares

	No. of shares 100	Name of corporation 105	Class of shares 106	Date of acquisition YYYY/MM/DD 110	Proceeds of disposition 120	Adjusted cost base 130	Outlays and expenses (dispositions) 140	Gain (or loss) (column 120 less cols. 130 and 140) 150	Foreign source
1									
				Totals					

Total adjustment under subsection 112(3) of the ITA to all losses identified in Part 1 160

Actual gain or loss from the disposition of shares (total of line 150 **plus** line 160) . . . . . A

Part 2 – Real estate – Do not include losses on depreciable property

	Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	Date of acquisition YYYY/MM/DD 210	Proceeds of disposition 220	Adjusted cost base 230	Outlays and expenses (dispositions) 240	Gain (or loss) (column 220 less cols. 230 and 240) 250	Foreign source
1	Rainham Road FISHERVILLE ON		39,000	21,753	3,684	13,563	
2							
		Totals	39,000	21,753	3,684	13,563	B

Part 3 – Bonds

	Face value 300	Maturity date 305	Name of issuer 307	Date of acquisition YYYY/MM/DD 310	Proceeds of disposition 320	Adjusted cost base 330	Outlays and expenses (dispositions) 340	Gain (or loss) (column 320 less cols. 330 and 340) 350	Foreign source
1									
				Totals					C

Part 4 – Other properties – Do not include losses on depreciable property

	Description 400	Date of acquisition YYYY/MM/DD 410	Proceeds of disposition 420	Adjusted cost base 430	Outlays and expenses (dispositions) 440	Gain (or loss) (column 420 less cols. 430 and 440) 450	Foreign source
1							
		Totals					D

Part 5 – Personal-use property (Do not include listed personal property)

	Description 500	Date of acquisition YYYY/MM/DD 510	Proceeds of disposition 520	Adjusted cost base 530	Outlays and expenses (dispositions) 540	Gain only (column 520 less cols. 530 and 540) 550	Foreign source
1							
	Totals						E

Note: Losses are not deductible

Part 6 – Listed personal property

	Description 600	Date of acquisition YYYY/MM/DD 610	Proceeds of disposition 620	Adjusted cost base 630	Outlays and expenses (dispositions) 640	Gain (or loss) (column 620 less cols. 630 and 640) 650	Foreign source
1							
	Totals						

Note: Net listed personal property losses may only be applied against listed personal property gains

Subtract: Unapplied listed personal property losses from other years 655

Amount from line 655 is from line 530 in Part 5 of Schedule 4

Net gains (or losses) F

Part 7 – Determining allowable business investment losses

Property qualifying for and resulting in an allowable business investment loss

	Name of small business corporation 900	Shares, enter 1; debt, enter 2 905	Date of acquisition YYYY/MM/DD 910	Proceeds of disposition 920	Adjusted cost base 930	Outlays and expenses (dispositions) 940	(Loss)(column 920 less cols. 930 and 940) 950	Foreign source
1								
	Totals							G

Note: Properties listed in Part 7 should not be included in any other parts of Schedule 6

Allowable business investment losses . . . . . Amount G _____ x 50 % = _____ H

Enter amount H on line 406 of Schedule 1

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss) . . . . . 13,563 I

Add: Foreign source

Capital gains dividend received in the year . . . . . 875 _____ J ☐

Capital gains reserve opening balance (from Schedule 13) . . . . . 880 _____ K

Subtotal (**add** amounts I, J, and K) 13,563 L

Deduct: Capital gains reserve closing balance (from Schedule 13) . . . . . 885 _____ M

Capital gains or losses (amount L minus amount M) 890 13,563

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses (amount from line 890 above) . . . . . 13,563 N

Deduct the following gains that are included in the amount N:

Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the *Income Tax Act*

realized prior to May 2, 2006 . . . . . _____ x 50 % = _____ O — Foreign source ☐

realized after May 1, 2006 . . . . . _____ P — Foreign source ☐

Subtotal: O **plus** P **895** _____

Gain on donation of ecologically sensitive land . . . . . .

realized prior to May 2, 2006 . . . . . _____ x 50 % = _____ Q — Foreign source ☐

realized after May 1, 2006 . . . . . _____ R — Foreign source ☐

Subtotal: Q **plus** R **896** _____

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . . _____ R-2 — Foreign source ☐

Total: line 895 plus line 896 plus R-2 _____ S

Amount N minus amount S . . . . . 13,563 T

Total capital losses: If amount T is a loss, enter it on line 210 of Schedule 4

Taxable capital gains: If amount T is a gain, enter it on this line and multiply . . . . . 13,563 x 50 % = 6,782 U

Enter amount U on line 113 of Schedule 1

T2 SCH 6 E (08)

Canada

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SCHEDULE 7

CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act*;
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part 1 Tax" in the *T2 Corporation – Income Tax Guide*.

Part 1 and Part 2 – Aggregate and foreign investment income calculation

	Canadian investment income	Foreign investment income	Aggregate investment income	
Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13	6,782		6,782	A1
Reserve's eligible portion (addition/deduction)				A2
Eligible portion of taxable capital gains included in the income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts A1 and A2)	6,782	001	002 6,782	A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		009	012	B
Net capital losses of other years claimed on line 332 on the T2 return			022	C
Total of amounts B and C				D
Amount A **minus** amount D (if negative, enter "0")	6,782		6,782	E
Total income from property (in box 32 include income from a specified investment business carried on in Canada other than income from a source outside Canada)				
Taxable dividends				
Other property income				
Total income from property		019	032	F
Exempt income		029	042	G
Amounts received from NISA Fund No. 2 (AGRI) that were included in computing the corporation's income for the year			052	H
Taxable dividends deductible (total of Column F on Schedule 3)		049	062	I
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		059	072	J
Total of amounts G, H, I, and J				K
Amount F **minus** amount K				L
Total of amount E **plus** amount L	6,782		6,782	M
Total losses from property (in box 82 include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)		069	082	N
Amount M **minus** amount N (if negative, enter "0")	6,782	079 L	092 O 6,782	

Note: The aggregate investment income is the aggregate world source income.

Enter amount L, foreign investment income, on line 445 of the T2 return.
Enter amount O, aggregate investment income, on line 440 of the T2 return.

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A	B	C
Partnership name 200	Total income (loss) of partnership from an active business 300	Corporation's share of amount in column B 310

D	E	F	G	H	I
Adjustments [add prior-year reserves under subsection 34.2(5), and deduct expenses incurred to earn partnership income, including any reserve under subsection 34.2(4)] 315	Corporation's income (loss) of the partnership (column C **plus** column D) 320	Number of days in the partnership's fiscal period 325	Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")** 330	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") 340
Total 350			**Total** 385		360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount 370

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) 380

Total of lines 370 and 380 . . . . . ▶ J

Amount at line 385 or line J, whichever is less 390

Specified partnership income (line 360 **plus** line 390) 400

* Use one of the following business limits to calculate column G, whichever applies:

- $250,000 if the corporation's tax year ends in 2004;
- $300,000 if the corporation's tax year ends in 2005 or 2006; or
- $400,000 if the corporation's tax year ends after 2006.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 above (if the net amount is negative, enter "0" on line O) . . . . . K

Add: Specified partnership loss (from line 380 above) L

Subtotal M

Deduct: Specified partnership income (from line 400 above) . . . . . N

nership income (enter on line S below) . . . . . 450 O

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return			2,283,727	P
Deduct: Foreign business income after deducting related expenses*	500			
Taxable capital gains **minus** allowable capital loss – amount A **minus** amount B* (page 1)**		6,782		
Net property income = amount F **minus** amount G, H, and N* (page 1)			Q	
Personal services business income after deducting related expenses*	520			
		6,782 ▶	6,782	
		Net amount	2,276,945	R
Deduct: Partnership income (line 450 above)				S
Income from active business carried on in Canada (enter on line 400 of the T2 return – if negative, enter "0")			2,276,945	T

* If negative, **add** instead of **subtracting**.
**This amount may only be negative to the extent of any allowable business investment losses.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

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 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 (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	8		619,731	324,893		449	162,222	781,953	20	0	0	156,391	787,784
2	10		378,383	47,890		12,311	17,790	396,172	30	0	0	118,852	295,110
3	12		75,969	416,384		0	208,192	284,161	100	0	0	284,161	208,192
4	1		26,887,210			0		26,887,210	4	0	0	1,075,488	25,811,722
5	17	Parking Lot	73,897			0		73,897	8	0	0	5,912	67,985
6	45		66,082			0		66,082	45	0	0	29,737	36,345
7	46		573			0		573	30	0	0	172	401
8	47		4,881,786	3,570,990		8,100	1,781,445	6,663,231	8	0	0	533,058	7,911,618
9	50		33,393	40,865		0	20,433	53,825	55	0	0	29,604	44,654
10	1	March 2007 Buildings		83,776		0	41,888	41,888	6	0	0	2,513	81,263
		Total	33,017,024	4,484,798		20,860	2,231,970	35,248,992				2,235,888	35,245,074

* 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*.

**** 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.

T2 SCH 8 (06)

Canada

The taxpayer elects to have 2008 building additions in a separate class 1.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

›e of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	HALDIMAND COUNTY ENERGY INC.		89076 2412 RC0001	3					
2.	HALDIMAND COUNTY GENERATION		89075 7412 RC0001	3					
3.	HALDIMAND COUNTY UTILITIES IN		86391 7795 RC0001	1	1,001	100.000			17,144,796

Note 1: Enter "NR" if a corporation is not registered.
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.

T2 SCH 9(99)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

- 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 — 319,012 — 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) 230 319,012 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) . . . . . 319,012 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 319,012

less amount from line 249 _____

Current year deduction . . . . . 319,012 x 7.00 % = 250 22,331 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 22,331 ▶ 22,331 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . 300 296,681 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 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 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
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

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 2008

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 Asso-ciation code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	1	400,000	100.0000	400,000
2	HALDIMAND COUNTY ENERGY INC.	89076 2412 RC0001	1	400,000		
3	HALDIMAND COUNTY GENERATION INC.	89075 7412 RC0001	1	400,000		
4	HALDIMAND COUNTY UTILITIES INC.	86391 7795 RC0001	1	400,000		
				Total	100.0000	400,000 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. In this case, 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 (06)

Canada

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward (proposed legislation) for credits earned in tax years that end after 1997 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - qualified expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Pamphlet T4052, *An Introduction to the Scientific Research and Experimental Development Program*; and Guide T4088, *Claiming Scientific Research and ExperimentalDevelopment* – Guide to Form T661 *Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures made after February 22, 2005, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone. For SR&ED expenditures made before February 23, 2005, the expression "in Canada" generally includes the 12 nautical mile territorial sea.

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

Part 1 -- Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC) throughout the tax year, this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC throughout the current tax year that incurred qualified expenditures for SR&ED in any area in Canada after 1995	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures after 2004:	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment after May 1, 2006	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 -- Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** (proposed legislation) is defined under subsection 127.1(2). The corporation has to be a CCPC throughout the current tax year and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than its qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC for tax years ending after March 22, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are not qualifying corporations may also earn a 100% refund on their share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? **102** 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5 _____

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year . . . . . _____

Deduct:

Credit deemed as a remittance of co-op corporations . . . . . 210 _____

Credit expired* . . . . . 215 _____

Subtotal _____ ▶ _____

ITC at the beginning of the tax year . . . . . 220 _____

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . . . 230 _____

ITC from repayment of assistance . . . . . 235 _____

Total current-year credit: total of column 125 _____ x 10 % = 240 _____

Credit allocated from a partnership . . . . . 250 _____

Subtotal _____ ▶ _____

Total credit available . . . . . _____

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) . . . . . 260 _____

Credit carried back to the previous year(s) (from Part 6) . . . . . _____ A

Credit transferred to offset Part VII tax liability . . . . . 280 _____

Subtotal _____ ▶ _____

Credit balance before refund . . . . . _____ B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) . . . . . 310 _____

ITC closing balance of investments from qualified property . . . . . 320 _____

* The credit expires after 20 tax years (proposed legislation) if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

. . . . . Credit to be applied 901 _____

. . . . . Credit to be applied 902 _____

. . . . . Credit to be applied 903 _____

Total (enter on line A in Part 5) _____

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) . . . . . _____ C

Credit balance before refund (amount B from Part 5) . . . . . _____ D

Refund (40 % of amount C or D, whichever is less) . . . . . _____ E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
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SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures (including contributions to agricultural organizations for SR&ED)*	350	
Capital expenditures	360	
Repayments made in the year (from line 560 on Form T661)	370	
Total (this must equal the amount from line 570 on Form T661)*	380	

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC throughout the current tax year.

Note: A CCPC that calculates SR&ED expenditure limit for tax years ending after March 22, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes ☐ 2 No ☒

Complete lines 390, 395 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied).	390	2,532,601
b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return).	395	
c) Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. 25,554,664	398	15,554,664

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC throughout the current tax year

For stand-alone corporations:

Calculation 1: tax year ends before February 26, 2008.
($6,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x line 395 from Part 9 divided by line 4 on page 4 of the T2 return. _____

Calculation 2: tax year starts after February 26, 2008.
($7,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more)) x ($40,000,000 minus line 398 from Part 9) divided by $40,000,000. _____

Calculation 3: tax year includes February 26, 2008.

AA + ((BB minus AA) x (CC divided by DD)) where,

AA = ($6,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x line 395 from Part 9 divided by line 4 on page 4 of the T2 return.

BB = ($7,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more)) x ($40,000,000 minus line 398 from Part 9) divided by $40,000,000.

CC = number of days in the tax year after February 25, 2008;

DD = number of days in the tax year. _____

Enter the amount from Calculation 1, 2 or 3, whichever is applicable. _____ G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 400 _____ *H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H _____ x Number of days in the tax year _____ 366 / 365 = _____ I

SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) 410 _____

* Amount G or H cannot be more than $3,000,000 ($2,000,000 if tax year ending before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 % =		J
Line 350 minus line 410 (if negative, enter "0")	430		x	20 % =		K
Line 410 minus line 350 (if negative, enter "0")			L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 % =		M
Line 360 minus line L (if negative, enter "0")	450		x	20 % =		N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 % =		
480		x	20 % =		
			Total	▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12)

* For corporations that are not CCPCs throughout the year, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations	510		
Credit expired*	515		
Subtotal		▶	

ITC at the beginning of the tax year — 520

Add:

Credit transferred on amalgamation or wind-up of subsidiary	530		
Total current-year credit	540		
Credit allocated from a partnership	550		
Subtotal		▶	

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B2 in Part 30)	560		
Credit carried back to the previous year(s) (from Part 13)		P	
Credit transferred to offset Part VII tax liability	580		
Subtotal		▶	

Credit balance before refund — Q

Deduct:

Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies) — 610

ITC closing balance on SR&ED — 620

* The credit expires after 20 tax years (proposed legislation) if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	

Total (enter on line P in Part 12)

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes ☐ 2 No ☒

Credit balance before refund (amount Q from Part 12) . . . . . R

Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11) S

Refundable credits (amount R or S, whichever is less)* . . . . . T

Amount J from Part 11 . . . . . U

Subtract: Amount T or U, whichever is less V

Net amount (if negative, enter "0") . . . . . W

Amount W x 40 % X

Add: Amount V . . . . . Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) . . . . . Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) . . . . . AA

Amount J from Part 11 . . . . . BB

Subtract: Amount AA or BB, whichever is less CC

Net amount (if negative, enter "0") . . . . . DD

Amount M from Part 11 . . . . . EE

Amount DD or EE, whichever is less x 40 % . . . . . FF

Add : Amount CC above . . . . . GG

Refund of ITC (amounts FF **plus** GG) . . . . . HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ____ ||

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula **(A x B) - C**	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) _____ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12 on page 5. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 _____ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16 . . . . . _____ LL

Recaptured ITC for calculation 2 from line JJ in Part 16 above . . . . . _____ MM

Recaptured ITC for calculation 3 from line KK in Part 16 above . . . . . _____ NN

Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN . . . . . _____ OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	PP
Geological, geophysical, or geochemical surveys	811	QQ
Drilling by rotary, diamond, percussion, or other methods	812	RR
Trenching, digging test pits, and preliminary sampling	813	SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	TT
Sinking a mine shaft, constructing an adit, or other underground entry	821	UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts at column 826 ▶ VV

Total pre-production mining expenditures (add amounts PP to VV) 830

Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above 832

Excess (line 830 minus line 832) (if negative, enter "0") WW

Add: Repayments of government and non-government assistance 835 XX

Pre-production mining expenditures (amount WW plus amount XX) YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . . . _____

Deduct:

Credit deemed as a remittance of co-op corporations . . . . . 841 _____

Credit expired* . . . . . 845 _____

Subtotal _____ ▶ _____

ITC at the beginning of the tax year . . . . . 850 _____

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . . . 860 _____

Expenditures from line YY in Part 18 . . . . . 870 _____ x 10 % = ... 880 _____

Total credit available . . . . . _____

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) . . . . . 885 _____

Credit carried back to the previous year(s) (from Part 20) . . . . . _____ CCC

Subtotal _____ ▶ _____

ITC closing balance from pre-production mining expenditures . . . . . 890 _____

* The credit expires after 20 tax years (proposed legislation) if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day
previous tax year			
2nd previous tax year			
3rd previous tax year			

. . . . . Credit to be applied 921 _____

. . . . . Credit to be applied 922 _____

. . . . . Credit to be applied 923 _____

Total (enter on line CCC in Part 19) _____

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages **or** $2,000.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	D17399 TOM PRIDMORE	POWERLINE TECHNICIAN	70,073	7,007	2,000
2.	PA1887 RICHARD VANKURE	POWERLINE TECHNICIAN	41,904	4,190	2,000
3.	PA1888 KIERAN KELLEHER	POWERLINE TECHNICIAN	43,724	4,372	2,000
4.					
				Total current-year credit (enter at line 640)	6,000

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	612		
Credit expired after 20 tax years	615		
Subtotal		▶	
ITC at the beginning of the tax year	625		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	630		
ITC from repayment of assistance	635		
Total current-year credit (total of column 605)	640	6,000	
Credit allocated from a partnership	655		
Subtotal		6,000 ▶	6,000
Total credit available			6,000
Deduct:			
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	6,000	
Credit carried back to the previous year(s) (from Part 23)		DDD	
Subtotal		6,000 ▶	6,000
ITC closing balance from apprenticeship job creation expenditures	690		

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	Year	Month	Day		
1st previous tax year				Credit to be applied	931
2nd previous tax year				Credit to be applied	932
3rd previous tax year				Credit to be applied	933
				Total (enter on line DDD in Part 22)	

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

*CCA: capital cost allowance

Total cost of depreciable property from the current tax year 715 _____ EEE

Add: Specified child care start-up expenditures from the current tax year . . . . . 705 _____ FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . _____ GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) . . . . . 725 _____ HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") _____ III

Add: Repayments of government and non-government assistance . . . . . 735 _____ JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) . . . . . 745 _____

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

ble expenditures (line 745) . . . . . x 25 % = KKK

Number of child care spaces . . . . . 755 x $ 10,000 = LLL

ITC from child care spaces expenditures (amount KKK or LLL, whichever is less) . . . . . MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year . . . . .

Deduct:

Credit deemed as a remittance of co-op corporations 765

Credit expired after 20 tax years 770

Subtotal ▶

ITC at the beginning of the tax year 775

Add:

Credit transferred on amalgamation or wind-up of subsidiary 777

Total current-year credit (amount MMM above) 780

Credit allocated from a partnership 782

Subtotal ▶

Total credit available . . . . .

Deduct:

Credit deducted from Part I tax (enter on line B5 in Part 30) 785

Credit carried back to the previous year(s) (from Part 27) . . . . . NNN

Subtotal ▶

ITC closing balance from child care spaces expenditures 790

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day		
1st previous tax year	2007-12-31			Credit to be applied	941
2nd previous tax year	2006-12-31			Credit to be applied	942
3rd previous tax year	2005-12-31			Credit to be applied	943

Total (enter on line NNN in Part 26)

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . 792 _____ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . 795 _____

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . 797 _____

Amount from line 795 or line 797, whichever is less . . . . . _____ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26 on page 13. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC 799 _____ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . _____ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17 . . . . . _____ A1

Recaptured child care spaces ITC from line QQQ in Part 28 above . . . . . _____ A2

Total recapture of investment tax credit – Add lines A1 and A2
Enter amount A3 on line 602 of the T2 return. . . . . _____ A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) . . . . . _____ B1

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) . . . . . _____ B2

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) . . . . . _____ B3

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) 6,000 B4

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) . . . . . _____ B5

Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) 6,000 B6
Enter amount B6 at line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

A class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
6,000	6,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2001-09-30				
2000-12-31				
1999-12-31				*
1998-12-31				
1997-12-31				
1996-12-31				
1995-12-31				
1994-12-31				
1993-12-31				
92-12-31				
1991-12-31				
1990-12-31				
1989-12-31				*
Total				

B+C+D+G **Total ITC utilized** 6,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

e of corporation	Business Number	Tax year end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	HALDIMAND COUNTY UTILITIES INC.	86391 7795 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

T2 SCH 50 (06)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

e of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

On: 2008-12-31

- 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 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
   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)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")			050	A
GRIP at the end of the previous tax year			100 8,806,342	B
Taxable income for the year (DICs enter "0")*		110 2,283,727		C
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 6,782			
Subtotal (**add** lines 120, 130, and 140)	6,782 ▶	6,782		D
Income taxable at the general corporate rate (line C **minus** line D)		150 2,276,945		
After-tax income (line 150 **multiplied** by 68 %)			190 1,548,323	E
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)		▶		F
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	G
Subtotal (**add** lines A or B (as applicable), E, F, and G)			10,354,665	H
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)		▶		I
GRIP before adjustment for specified future tax consequences (line H **minus** line I) (amount can be negative)			490 10,354,665	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)			560	
GRIP at the end of the year (line 490 **minus** line 560)			590 10,354,665	

Enter this amount on line 160 on Schedule 55.

*** Note:** 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.

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 of page 1 or leave it blank.

First previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year	2,532,601	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)	▶	O1	
Subtotal (line J1 **minus** line O1) (if negative, enter "0")	2,532,601 ▶		2,532,601 P1

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 Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S1

Aggregate investment income (line 440 of the T2 return) T1

Subtotal (**add** lines R1,S1, and T1) ▶ V1

Subtotal (line Q1 **minus** line V1) (if negative, enter "0") ▶ W1

Subtotal (line P1 **minus** line W1) (if negative, enter "0") X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 **multiplied by** 68 %) . . . 500

Second previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year 3,968,781 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 300,000 L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N2

Subtotal (**add** lines K2, L2, M2, and N2) 300,000 ▶ 300,000 O2

Subtotal (line J2 **minus** line O2) (if negative, enter "0") 3,668,781 ▶ 3,668,781 P2

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 Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S2

Aggregate investment income (line 440 of the T2 return) T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U2

Subtotal (**add** lines R2, S2, T2, and U2) ▶ V2

Subtotal (line Q2 **minus** line V2) (if negative, enter "0") ▶ W2

Subtotal (line P2 **minus** line W2) (if negative, enter "0") X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 **multiplied by** 68 %) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2005-12-31

Taxable income before specified future tax consequences from current tax year 2,065,056 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

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . _____ N3

Subtotal (**add** lines K3, L3, M3, and N3) _____ ▶ _____ O3

Subtotal (line J3 **minus** line O3) (if negative, enter "0") 2,065,056 ▶ 2,065,056 P3

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 . . . . . _____ Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ S3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ T3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . _____ U3

Subtotal (**add** lines R3, S3, T3, and U3) _____ ▶ _____ V3

Subtotal (line Q3 **minus** line V3) (if negative, enter "0") _____ ▶ _____ W3

Subtotal (line P3 **minus** line W3) (if negative, enter "0") _____ X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) . . . **540** _____

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . _____ Y

Enter amount Y on line 560.

***Note**: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or 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 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 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 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 DIC in its last tax year), or the corporation is becoming a CCPC

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 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 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 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.

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HALDIMAND COUNTY HYDRO INC.	89075 9814 RC0001	2008-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation,* or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		449,627	
Total taxable dividends paid in the tax year	100	449,627	
Total eligible dividends paid in the tax year	150		
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")	160	10,354,665	
Excessive eligible dividend designation (line 150 **minus** line 160)			A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%) x 20 %	190		

Enter the amount from line 190 at line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)			B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%) x 20 %	290		

Enter the amount from line 290 at line 710 of the T2 return.

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

CLIENT'S COPY

Apprenticeship Training Tax Credit (ATTC)

CT23 Schedule 114

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

Instructions for completing the ATTC Claim Form

- Enter the relevant details for each eligible apprentice, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each eligible apprentice.
- Enter the total tax credit claimed on line 203, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Enter the total number of apprentices hired on line 202, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Corporations are eligible for a 25% (30% in the case of corporations with payroll not exceeding $400,000) refundable tax credit on wages and salaries paid or payable for services performed after May 18, 2004 by an eligible apprentice during the first 36 months of an apprenticeship.
- The maximum amount of credit that can be claimed in respect of each eligible apprentice is $5,000 per year to a maximum of $15,000 over the first 36 months of the apprenticeship. The maximum annual tax credit of $5,000 is pro-rated for the number of days the apprentice was employed during the taxation year.
- The credit is *considered government assistance* and is therefore *to be included in income* in the year the credit is claimed.

Summary of Apprenticeship Training Tax Credit Claimed

Complete a separate entry for each eligible apprentice that is in a qualifying skilled trade and hired before January 1, 2012. This credit applies to **salaries and wages paid after May 18, 2004 and before January 1, 2015** to eligible apprentices during the first 36 months of an apprenticeship.

Example: A taxpayer, with a December 31, 2004 taxation year end, hires an otherwise eligible apprentice on June 1, 2004 at a salary of $3,500 per month. The taxpayer's salaries and wages in the preceding taxation year were $700,000. The credit claimed is the lesser of ***(1)** 25% of salaries paid to the apprentice during the period of employment (25% x $3,500 x 7 = $6,125), and ***(2)** $5,000 multiplied by the number of days the apprentice was employed during the taxation year, divided by the total number of days in the calendar year ($5,000 x 214/366 = $2,923). Hence, the credit claimed in the 2004 taxation year is $2,923.

Eligible Apprenticeship

Trade Code	Description of Apprenticeship Program	Apprentice Name and Social Insurance No. (SIN)	Registration Date of Apprenticeship Contract or Training Agreement (year month day)	Contract or Agreement No.	Employment Period (year month day)	Eligible Expenditures (EE)	* Credit Claimed (see notes below)
434a	Lineworker	Name KIERAN KELLEHER SIN 287 039 507	2008-01-11	PA1888	From 2008-01-11 To 2008-12-31	43,724	4,863
434a	Lineworker	Name RICHARD VANKUREN SIN 505 744 052	2008-01-11	PA1887	From 2008-01-11 To 2008-12-31	41,904	4,863
434a	Lineworker	Name THOMAS PRIDMORE SIN 505 956 391	2007-01-12	D17399	From 2008-01-01 To 2008-12-31	70,073	5,000
If insufficient space, attach schedule					**Totals**	5874 155,701	5898 14,726

Transfer to 203 ***on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8***

Corporation's salaries & wages paid in the preceding taxation year A $ 2,000,000

- If A is $600,000 or greater use 25%.
- If A is $400,000 or less use 30%.
- If A is over $400,000 but less than $600,000 use the following formula to calculate the specified percentage:

  Specified percentage = .30 – [.05 (From A 2,000,000 – $400,000) ÷ $200,000]

Indicate specified percentage used 25.0000 %

*** Credit claimed equals lesser of:**

(1) EE multiplied by the specified percentage, and

(2) $5,000 x number of days the apprentice was employed in the taxation year
365 (366 if leap year)

Total Number of Apprentices . . . . . = 5896 3

Transfer to 202 ***on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8***

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007

CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No **Page 1 of 20**

Corporation's Legal Name *(including punctuation)*
HALDIMAND COUNTY HYDRO INC.

Ontario Corporations Tax Account No. (MOF)
7299908

Mailing Address
1 GREENDALE DRIVE R. R. #2
CALEDONIA
ON CA N3W 2J3

This Return covers the Taxation Year
Start: year month day 2008-01-01
End: year month day 2008-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes | Date of Change: year month day

Date of Incorporation or Amalgamation
year month day 2000-10-13

Registered/Head Office Address
1 GREENDALE DRIVE R. R. #2
CALEDONIA
ON CA N3W 2J3

Ontario Corporation No. (MGS) 1800101

Location of Books and Records
GREENDALE DRIVE R. R. #2
CALEDONIA
ON CA N3W 2J3

Canada Revenue Agency Business No.
If applicable, enter
89075 9814 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
LLOYD PAYNE	(905) 765-5211	

Jurisdiction Incorporated: ONTARIO

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced: year month day
Ceased: year month day
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s)

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ [X] No Change

Preferred Language / *Langue de préférence*
[X] English *anglais* [ ] French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*
LLOYD PAYNE

Title D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

...tification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [ ] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change -- Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired (year / month / day)

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?

Are you requesting a refund due to:

[ ]	[X]	the Carry-back of a Loss?
[X]	[ ]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[X]	[ ]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.) 111292775

Specify major business activity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	2,283,727
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax _____ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses From 715	–	From 704	
Net capital losses (page 16) 13,563 x inclusion rate 50.000000 %	–	714	6,782
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	2,276,945
Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	2,276,945

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable)	2,276,945	x	30 100.0000 % Ontario Allocation	x	12.5 %	x	Days after Dec. 31, 2002 and before Jan. 1, 2004 33 ____ ÷ Total Days 73 366	= +	29	
From 10 (or 20 if applicable)	2,276,945	x	30 100.0000 % Ontario Allocation	x	14 %	x	Days after Dec. 31, 2003 34 366 ÷ Total Days 73 366	= +	32	318,772
Income Tax Payable (before deduction of tax credits) 29 + 32								=	40	318,772

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) [X] Yes [ ] No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))		50	2,276,945
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	2,283,727	
Add: Losses of other years deducted for federal purposes (fed.s.111)	+ 52		
Subtract: Losses of other years deducted for Ontario purposes (s.34)	– 53	6,782	
	=	2,276,945	54 2,276,945
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000

Ontario Business Limit Calculation

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ____ ÷ ** 366) = + 46 _____

400,000 x (Days after Dec. 31, 2003: 34 366 ÷ ** 366) = + 47 _____

Business Limit for Ontario purposes 46 + 47 = 44 500,000 x (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated. 48 100.0000 %) = 45 500,000

Income eligible for the IDSBC From 30 100.0000 % *** Ontario Allocation x 56 500,000 = 60 500,000

Least of 50, 54 or 45

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate 7 % x Number of Days in Taxation Year: Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 366 = + [89]

8.5 % x Days after Dec. 31, 2003 [34] 366 ÷ Total Days [73] 366 = + [90] 8.5000

IDSBC Rate for Taxation Year [89] + [90] = [78] 8.5000

Claim From [60] 500,000 . x From [78] 8.5000 % = [70] 42,500 .

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 500,000 in [114] below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** From [10] (or [20] if applicable) + [80] 2,276,945 .

If you are a member of an associated group (X) [81] X (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	* Taxable Income (if loss, enter nil)
HALDIMAND COUNTY ENERGY INC.	7295044	2008-12-31	+ [82] 94,508 .
HALDIMAND COUNTY GENERATION INC.	1800100	2008-12-31	+ [83] .
HALDIMAND COUNTY UTILITIES INC.	7294862	2008-12-31	+ [84] .

Aggregate Taxable Income [80] + [82] + [83] + [84], etc. = [85] 2,371,453 .

320,000 x Number of Days in Taxation Year: Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 366 = + [115] .

400,000 x Days after Dec. 31, 2003 [34] 366 ÷ Total Days [73] 366 = + [116] .

[115] + [116] = 500,000 . – [114] 500,000 .

(If negative, enter nil) = [86] 1,871,453 .

Calculation of Specified Rate for Surtax 4.6670 % x Number of Days in Taxation Year: Days after Dec. 31, 2002 [38] ÷ Total Days [73] 366 = + [97] 4.2500

From [86] 1,871,453 . x From [97] 4.2500 % = [87] 79,537 .

From [87] 79,537 . x From [60] 500,000 . ÷ From [114] 500,000 . = [88] 79,537 .

Surtax Lesser of [70] or [88] = [100] 42,500

* ***Short Taxation Years*** – Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

110

M ufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits + 120

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) − From 56 500,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 42,500 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 500,000

*Ontario Allocation

Lesser of 56 or 121 + 122 500,000

120 − 56 + 122 = 130

Taxable Income + From 10 2,276,945

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) − From 56 500,000

Add: Adjustments for Surtax on Canadian-controlled private corporations + From 122 500,000

Subtract: Taxable Income 10 2,276,945 X Allocation % to jurisdictions outside Canada − 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses − 141 6,782

1[illegible] − 56 + 122 − 140 − 141 = 142 2,270,163

Claim

Number of Days in Taxation Year

143 _____ Lesser of 130 or 142 X From 30 100.0000 % Ontario Allocation X 1.5 % X (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ÷ Total Days: 73 366) = + 154

143 _____ Lesser of 130 or 142 X From 30 100.0000 % Ontario Allocation X 2 % X (Days after Dec. 31, 2003: 34 366 ÷ Total Days: 73 366) = + 156

M&P claim for taxation year 154 + 156 = 160

* ***Note:*** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity = 162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 _____ Credit Claimed 180

Subtotal of Income Tax 40 − 70 + 100 − 110 − 160 − 161 − 162 − 170 − 180 = 190 318,772

continued on Page 7

Income Tax *continued from Page 6*

S ified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192 4,517

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194
Eligible Credit From 6598 CT23 Schedule 115 *(Attach Schedule 115)* + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
A s to qualifying R&D expenditures under an eligible research institute contract.
El e Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896
Applies to employment of eligible apprentices. 202 3
Eligible Credit From 5898 CT23 Schedule 114 *(Attach Schedule 114)* + 203 14,726

Other (specify) _____ + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220 19,243

Specified Tax Credits ***Applied to reduce Income Tax*** = 225 19,243

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 299,529

› determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation + 240 48,339,075 .

Total Revenue of the corporation + 241 34,496,899 .

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 X (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
HALDIMAND COUNTY ENERGY INC.	7295044	2008-12-31	+ 243 530,666 .	+ 244 508,780 .
HALDIMAND COUNTY GENERATION INC.	1800100	2008-12-31	+ 245 2 .	+ 246 .
			+ 247 .	+ 248 .
Aggregate Total Assets 240 + 243 + 245 + 247, etc.			= 249 48,869,743 .	
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.				= 250 35,005,679 .

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable – CMT Base From Schedule 101 2136 3,285,446 . (If negative, enter zero) X From 30 100.0000 % (Ontario Allocation) X 4 % = 276 131,418 .

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)* – 277 .

Subtract: Income Tax – From 190 318,772 .

Net CMT Payable (If negative, enter Nil on Page 17.) = 280 -187,354 .

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333 .

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) + From 190 318,772 .

Gross CMT Payable + From 276 131,418 .

Subtract: Foreign Tax Credit for CMT purposes – From 277 .

If 276 – 277 is negative, enter NIL in 290 = 131,418 . – 290 131,418 .

Income Tax eligible for CMT Credit = 300 187,354 .

B. Income Tax (after deduction of specified credits) + From 230 299,529 .

Subtract: CMT credit used to reduce income taxes – 310 .

Income Tax = 320 299,529 .

Transfer to page 17

If B apply, 310 ***cannot exceed the lesser of*** 230, 300 ***and your CMT credit carryover available*** 2333.

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 *and* [illegible] *on page 10 then proceed to page 13.*

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 *and* 430 *are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in* 550 *on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	17,144,796
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	8,473,801
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	2,735,909
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	859,542
Bank loans (Int.B. 3013R)	+	354	600,000
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	10,665,000
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
C[illegible]gent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
O[illegible], reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	1,102,125
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	41,581,173
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	41,581,173
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	41,581,173

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
S[illegible] of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	

continued on Page 10

DOLLARS ONLY

Total Assets (Int.B. 3015R)

Total Assets per balance sheet	+	420	48,339,075
Mortgages or other liabilities deducted from assets	+	421	
S[illegible] of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Su[illegible]act: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	48,339,075
Amounts in 360 and 361 (if deducted from assets)	+	440	
Subtract: Amounts in 371, 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	48,339,075

Investment Allowance ((410 ÷ 450) x 390 — **Not to exceed** 410) = 460

Taxable Capital 390 – 460 = 470 — 41,581,173

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue) 480 — 34,496,899

Total Assets (as adjusted) From 430 — 48,339,075

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

		Days after Dec. 31, 2004 and before Jan. 1, 2006		Total Days				
7,500,000	x	36	÷	73	366	= +	501	
		Days after Dec. 31, 2005 and before Jan. 1, 2007		Total Days				
10,000,000	x	37	÷	73	366	= +	502	
		Days after Dec. 31, 2006 and before Jan. 1, 2008		Total Days				
12,500,000	x	38	÷	73	366	= +	504	
		Days after Dec. 31, 2007		Total Days				
15,000,000	x	39 366	÷	73	366	= +	505	15,000,000

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 — 15,000,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

		Days before Jan. 1, 2007		Total Days				
0.3 %	x	556	÷	73	366	= +	511	%
		Days after Dec. 31, 2006 and before Jan. 1, 2009		Total Days				
0.225 %	x	557 366	÷	73	366	= +	512	0.2250 %

Capital Tax Rate 511 + 512 = 516 — 0.2250 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If [430] and [480] on page 10 are both $3,000,000 or less, enter NIL in [550] on page 12 and complete the return from that point.

C2. If Taxable Capital in [470] is **equal to or less than the TCD** in [503], enter NIL in [550] on page 12 and complete the return from that point.

C3. If Taxable Capital in [470] **exceeds the TCD** in [503], complete the following calculation and transfer the amount from [523] to [543] on page 12, and complete the return from that point.

+ From [470] _____ .
− From [503] _____ .
= [471] _____ . x From [30] 100.00000 % (Ontario Allocation) x From [516] 0.2250 % (Capital Tax Rate) x [555] 366 / 366 (366 if leap year) (Days in taxation year — *If floating taxation year, refer to Guide.*) = + [523] _____ . *Transfer to* [543] *on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either [509] or [524] and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ [509] (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital [470] on page 10 is equal to or less than the TCD [503] on page 10, enter NIL in [550] on page 12 and complete the return from that point.

If Taxable Capital [470] on page 10 exceeds the TCD [503] on page 10, proceed to **Section E**, enter the TCD amount in [542] in Section E, and complete Section E and the return from that point.

D2. ☒ [524] (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 + From 470 41,581,173 .

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
HALDIMAND COUNTY ENERGY INC.	7295044	2008-12-31	+ 531 475,910 .
HALDIMAND COUNTY GENERATION INC.	1800100	2008-12-31	+ 532 2 .
HALDIMAND COUNTY UTILITIES INC.	7294862	2008-12-31	+ 533 .
Aggregate Taxable Capital 470 + 531 + 532 + 533, etc.			= 540 42,057,085 .

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.
Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 41,581,173 . ÷ From 540 42,057,085 . X From 503 15,000,000 . = 541 14,830,262 .

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

591 (X if applicable) **Election filed.** *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+	From 470	41,581,173 .										**Total Capital Tax for the taxation year**
−	542	14,830,262 .										
=	471	26,750,911 .	X	From 30	100.0000 %	X	From 516	0.2250 %	X	555 366 / 366 *	= + 523	60,190 .
					Ontario Allocation			Capital Tax Rate		Days in taxation year / (366 if leap year)		*Transfer to* 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 . X From 30 100.0000 % (Ontario Allocation) X From 516 0.2250 % (Capital Tax Rate) = + 561 .

− Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 − From 995 .

= 562 .

Capital Tax 562 . X 555 366 / 366 * (Days in taxation year / 366 (366 if leap year)) = 563 .

Total Capital Tax for the taxation year

Transfer to 543 *and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits = 543 60,190 .

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* − 546 .

Capital Tax 543 − 546 *(amount cannot be negative)* = 550 60,190 .

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in [550] on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes [565] and [570]. Do not submit with this tax return.)

[565] _____ x [567] _____ % x From [30] 100.0000 % x Days in taxation year [555] 366 / 366 (366 if leap year) = + [569] _____

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1

Capital Tax Rate (1) *(Refer to Guide)*

Ontario Allocation *

[570] _____ x [571] _____ % x From [30] 100.0000 % x Days in taxation year [555] 366 / 366 (366 if leap year) = + [574] _____

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount

Capital Tax Rate (2) *(Refer to Guide)*

Ontario Allocation *

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) [569] + [574] = [575]

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – [585]

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions [575] – [585] = [586]

Transfer to [543] *on Page 12*

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements [587] x 2% = [588]

Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in [588] and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in [588].)

Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – [589]

Premium Tax [588] – [589] = [590]

Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 2,283,727 .
Transfer to Page 15

Add:

Federal capital cost allowance	+ 601	2,235,888 .
Federal cumulative eligible capital deduction	+ 602	22,331 .
Ontario taxable capital gain	+ 603	6,782 .
Federal non-allowable reserves. Balance beginning of year	+ 604	.
Federal allowable reserves. Balance end of year	+ 605	.
Ontario non-allowable reserves. Balance end of year	+ 606	.
Ontario allowable reserves. Balance beginning of year	+ 607	.
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608	.
Federal resource allowance *(Refer to Guide)*	+ 609	.
Federal depletion allowance	+ 610	.
Federal foreign exploration and development expenses	+ 611	.
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	.

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

			Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days				
612	.	x 5 / 12.5 x	33	÷	73	366	=+	633	.
			Days after Dec. 31, 2003		Total Days				
612	.	x 5 / 14 x	34	366 ÷	73	366	=+	634	.

Total add-back amount for Management fees, etc. 633 + 634 = . ▶ + 613

Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161 + 615

Add any negative amount in 473 from Ont. CT23 Schedule 161 + 616

Federal allowable business investment loss	+ 620	.
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+ 614	.

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 2,265,001 . ▶ 640 2,265,001 .
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	2,235,888 .
Ontario cumulative eligible capital deduction	+ 651	22,331 .
Federal taxable capital gain	+ 652	6,782 .
Ontario non-allowable reserves. Balance beginning of year	+ 653	.
Ontario allowable reserves. Balance end of year	+ 654	.
Federal non-allowable reserves. Balance end of year	+ 655	.
Federal allowable reserves. Balance beginning of year	+ 656	.
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	.
Ontario depletion allowance	+ 658	.
Ontario resource allowance *(Refer to Guide)*	+ 659	.
Ontario current cost adjustment *(Attach schedule)*	+ 661	.
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	.

Subtotal of deductions for this page 650 to 659 + 661 + 675 681 2,265,001 .
Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

c ...ued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1 - - - - - - - - - - - - - - - From ± 600 2,283,727 .

Total of Additions on page 14 - From = 640 2,265,001 .

Sub Total of deductions on page 14 - From = 681 2,265,001 .

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 .

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From 662 . x 100 / From 30 100.0000 Ontario Allocation] − From 662 . = 663 .

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 . x 30 % x 100 / From 30 100.0000 Ontario allocation] = 666 .

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 . x 100 % x 100 / From 30 100.0000 Ontario allocation] = 668 .

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [670 . x 30 % x 100 / From 30 100.0000 Ontario allocation] = 671 .

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 . x 15 % x 100 / From 30 100.0000 Ontario allocation] = 673 .

Ontario allowable business investment loss - - - - - - - - - - - - - - + 678 .

Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161** + 679 .

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) - - - - - - - - - + 677 .

Total of other deductions allowed by Ontario *(Attach schedule)* - - - - - - - - + 664 .

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 2,265,001 . ▶ 680 2,265,001 .

Net income (loss) for Ontario Purposes 600 + 640 − 680 - - - - - - - - - - - - - - - - - = 690 2,283,727 .
Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2) 33,061	720 (2)	730	740	750
Add: Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract: Utilized during the year to reduce taxable income	704 (2)	715 (2) (4) 13,563	724 (2)	734 (2) (4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal	707	717 13,563	727	737	747	757
Balance at End of Year	709 (8)	719 19,498	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year 2000-12-31	817 (9)	860 (9)		850	870
801 8th preceding taxation year 2001-09-30	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2001-12-31	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2002-12-31	820	830	840	853	873
804 5th preceding taxation year 2003-12-31	821	831	841	854	874
805 4th preceding taxation year 2004-12-31	822	832	842	855	875
806 3rd preceding taxation year 2005-12-31	823	833	843	856	876
807 2nd preceding taxation year 2006-12-31	824	834	844	857	877
808 1st preceding taxation year 2007-12-31	825	835	845	858	878
809 Current taxation year 2008-12-31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

( ) cludes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more pr s taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss	910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income				
Predecessor Ontario Corporation's Tax Account No. (MOF) / Taxation Year Ending year month day				
i) 3rd preceding — 901 — 2005-12-31	911	921	931	941
ii) 2nd preceding — 902 — 2006-12-31	912	922	932	942
iii) 1st preceding — 903 — 2007-12-31	913	923	933	943
Total loss to be carried back	From 706	From 716	From 726	From 736
B ıce of loss available for carry-forward	919	929	939	949

Summary

Income Tax	+ From 230 or 320	299,529	.
Corporate Minimum Tax	+ From 280		.
Capital Tax	+ From 550	60,190	.
Premium Tax	+ From 590		.
Total Tax Payable	= 950	359,719	.
Subtract: Payments	– 960	565,195	.
Capital Gains Refund (s.48)	– 965		.
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	– 985		.
Specified Tax Credits *(Refer to Guide)*	– 955		.
Other, specify _____	–		.
Balance	= 970	-206,476	.
If payment due — Enclosed *	990		.
If overpayment: Refund *(Refer to Guide)*	= 975	206,476	.
Apply to (year month day)	980		.

(includes credit interest)

ke your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*

LLOYD PAYNE

Title

PRESIDENT

Full Residence Address

Signature

Date 2009-05-22

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Other reserves not allowed as deductions for Income tax purposes (Attach schedule) (Int.B. 3012R)

Title AMOUNTS DEDUCTED IN EXCESS OF AMOUNTS BOOKED

Description	Amount
AMOUNTS DEDUCTED FOR ACCTING IN EXCESS OF AMOUNTS BOOKED FOR TAX:	
UCC	35,245,911 00
NBV - PER F/S LESS CONTRIBUTIONS IN AID OF CONSTRUCTION, LAND	-32,695,251 00
REGULATORY ASSETS - ENDING BALANCE	-728,070 00
FUTURE TAX ASSET	-720,465 00
Total	1,102,125 00

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)			±	2100	1,993,151
Subtract (to the extent reflected in net income/loss):					
Provision for recovery of income taxes / benefit of current income taxes			+	2101	
Provision for deferred income taxes (credits) / benefit of future income taxes			+	2102	
Equity income from corporations			+	2103	
Share of partnership(s)/joint venture(s) income			+	2104	
Dividends received/receivable deductible under fed.s.112			+	2105	
Dividends received/receivable deductible under fed.s.113			+	2106	
Dividends received/receivable deductible under fed.s.83(2)			+	2107	
Dividends received/receivable deductible under fed.s.138(6)			+	2108	
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1)		x 3	+	2109	
Subtotal			=		– 2110
Add (to extent reflected in net income/loss):					
Provision for current taxes / cost of current income taxes			+	2111	756,442
Provision for deferred income taxes (debits) / cost of future income taxes			+	2112	535,853
Equity losses from corporations			+	2113	
Share of partnership(s)/joint venture(s) losses			+	2114	
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))			+	2115	
Subtotal			=	1,292,295	+ 2116 1,292,295
Add/Subtract:					
Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years					
** Fed.s.85			+	2117	or – 2118
** Fed.s.85.1			+	2119	or – 2120
** Fed.s.97			+	2121	or – 2122
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years			+	2123	or – 2124
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years			+	2125	or – 2126
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years			+	2127	or – 2128
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income					– 2150
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)					– 2155
Subtotal (Additions)		=			+ 2129
Subtotal (Subtractions)			=		– 2130
** Other adjustments					± 2131
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131					= 2132 3,285,446
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss					± 2133
Adjusted net income (loss) (if loss, transfer to 2202 in ***Part 2: Continuity of CMT Losses Carried Forward.***)					= 2134 3,285,446
Deduct: * CMT losses: pre-1994 Loss			+	From 2210	
* CMT losses: other eligible losses			+	2211	
			=		– 2135

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base = 2136 3,285,446

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

P. 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)				+ 2201	
Add:	Current year's losses	+ 2202			
	Losses from predecessor corporations on amalgamation NOTE (3)	+ 2203			
	Losses from predecessor corporations on wind-up NOTE (3)	+ 2204			
	Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes				
Subtotal		=	▶	+ 2207	
Adjustments (attach schedule)				± 2208	
CMT losses available	2201 + 2207 ± 2208			= 2209	
Subtract:	Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210			
	Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211			
	Losses expired during the year	+ 2212			
Subtotal		=	▶	– 2213	
Balances at End of Year NOTE (5)	2209 – 2213			= 2214	

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 2000-12-31	2260	2280
2241	8th preceding taxation year 2001-09-30	2261	2281
2242	7th preceding taxation year 2001-12-31	2262	2282
2243	6th preceding taxation year 2002-12-31	2263	2283
2244	5th preceding taxation year 2003-12-31	2264	2284
2245	4th preceding taxation year 2004-12-31	2265	2285
2246	3rd preceding taxation year 2005-12-31	2266	2286
2247	2nd preceding taxation year 2006-12-31	2267	2287
2248	1st preceding taxation year 2007-12-31	2268	2288
2249	Current taxation year 2008-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

F 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) . . . . . + 2301

Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) . . . . . + From 312

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) . . . . . − From 190

Subtotal (If negative, enter NIL) . . . = ▶ − 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 − 2305 . . . = ▶ + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) . . . . . + 2325

Amalgamation (X) 2315 ☐ Yes Wind-up (X) 2320 ☐ Yes

Subtotal 2301 + 2310 + 2325 . . . . . = 2330

Adjustments *(Attach schedule)* . . . . . ± 2332

CMT Credit Carryover available 2330 ± 2332 . . . . . = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year . . . . . + 2334

Subtotal . . . . . = ▶ − 2335

Balance at End of Year NOTE (4) 2333 − 2335 . . . . . = 2336

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 2000-12-31	2360	2380
2341	8th preceding taxation year 2001-09-30	2361	2381
2342	7th preceding taxation year 2001-12-31	2362	2382
2343	6th preceding taxation year 2002-12-31	2363	2383
2344	5th preceding taxation year 2003-12-31	2364	2384
2345	4th preceding taxation year 2004-12-31	2365	2385
2346	3rd preceding taxation year 2005-12-31	2366	2386
2347	2nd preceding taxation year 2006-12-31	2367	2387
2348	1st preceding taxation year 2007-12-31	2368	2388
[illegible]	Current taxation year 2008-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 ***must equal amount in*** 2336.

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

C Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-12-31					
9th Prior Year	2000-12-31					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-12-31						
2000-12-31						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

C Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-12-31						
2000-12-31						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

C Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-12-31					
9th Prior Year	2000-12-31					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-12-31						
2000-12-31						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-12-31						
2000-12-31						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

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Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

ration's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Customer Deposits	+	436,567
DUE TO HALDIMAND COUNTY ENERGY INC	+	422,448
DUE TO HALDIMAND COUNTY UTILITIES	+	527
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	859,542

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Ontario Summary of Dispositions of Capital Property

2005 and later taxation years

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

- **For a corporation that has disposed of capital property or claimed an allowable business investment loss, or both, in the taxation year.**
- **This schedule may be used to make a designation under section 34(10) of the *Corporations Tax Act* provided the corporation has made a designation under paragraph 111(4) (e) of the *Income Tax Act* (Canada), if control of the corporation has been acquired by a person or group of persons.**

Part A: Designation under section 34(10) of the *Corporations Tax Act*

Complete part A if there are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e) of the *Income Tax Act* (Canada) or section 34(10) of the *Corporations Tax Act*.

Property	Class #	Date of disposition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Other adjustments	Designated amount	Gain or loss

Part B: Inter-provincial asset transfers

Complete part B if there was any disposition shown on the schedule as a result of a federal election under section 85 of the *Income Tax Act* (Canada) that transferred assets to a non-arm's length corporation with a permanent establishment in another Canadian jurisdiction.

Property	Class #	Corporation name of transferee/or	Date of disposition YYYY/MM/DD	Cost of asset in other jurisd.	Name of other jurisdiction	Allocation ratio to other jurisdictions	Ontario elected amount	Gain or loss
						%		
						%		
						%		
						%		

Part 1 – Shares

	1 Types of capital property			2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)
	No. of shares	Name of corporation	Class of shares						
1									
								Totals	A

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

	1 Types of capital property	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)

Part 2 – Real Estate *(Do not include losses on depreciable property)*

	Municipal address	2	3	4	5	6	7
1	Rainham Road FISHERVILLE ON			39,000	21,753	3,684	13,563
2							
						Totals	13,563 B

Part 3 – Bonds

	Face value	Maturity date YYYY/MM/DD	Name of issuer	2	3	4	5	6	7
1									
								Totals	C

Part 4 – Other properties *(Do not include losses on depreciable property)*

	Description	2	3	4	5	6	7
1							
						Totals	D

Part 5 – Personal-use property

	Description of capital property	2	3	4	5	6	7
1							

Note: *Losses are not deductible*

Net gain or (loss) E

Part 6 – Listed personal property

	Description	2	3	4	5	6	7
1							

Deduct: Unapplied listed personal property losses from other years . . . . . –

Note: *Net listed personal property losses may only be applied against personal property gains.*

Net gain or (loss) F

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

P 7 – Property qualifying for and resulting in an allowable business investment loss

	1 Name of small business corporation	Shares – enter 1 Debt – enter 2	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario loss (col. 4 less cols. 5 & 6)
1								
	Note: *Properties listed in Part 7 should not be included in any other Part of Schedule 6.*			**Totals**				

Net Loss **G**

Allowable business investment loss . . . . . **G** x 50 % = **G1**

Transfer to 678 *of the CT23 or CT8*

Determining capital gains and capital losses

Total of A to F (Do not include F if it is a loss)		13,563
Add: Amount (if any) of capital gain reserve opening balance from Schedule 13	+	
Capital gain dividend received in the year	+	
Subtotal	=	13,563
Deduct: Amount (if any) of capital gain reserve closing balance from Schedule 13	–	
Gain or Loss (excluding Allowable Business Investment Losses)	=	13,563 **H**

Determining taxable capital gains

Gain or Loss (excluding Allowable Business Investment Losses)				13,563 **H**
Deduct:				
Gain on donations (made to charities other than private foundations) of securities listed on a prescribed stock exchange				
realized prior to May 2, 2006		x 50 %	–	
realized after May 1, 2006			–	
Gain on donation of ecologically sensitive land				
realized prior to May 2, 2006		x 50 %	–	
realized after May 1, 2006			–	
Gains or Loss				13,563 **I**

Include 100% of the losses in box 711 *of the CT23 or CT8*

Taxable capital gains . . . . . 13,563 **I** x 50 % = 6,782 **J**

Transfer to 603 *of the CT23 or CT8*

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Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

Is the corporation electing under regulation 1101(5q)? 1 ☐ Yes 2 ☒ No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
8	619,731	324,893		449	944,175	162,222	781,953	20	0	0	156,391	787,784
10	378,383	47,890		12,311	413,962	17,790	396,172	30	0	0	118,852	295,110
12	75,969	416,384		0	492,353	208,192	284,161	100	0	0	284,161	208,192
1	26,887,210			0	26,887,210		26,887,210	4	0	0	1,075,488	25,811,722
17	73,897			0	73,897		73,897	8	0	0	5,912	67,985
45	66,082			0	66,082		66,082	45	0	0	29,737	36,345
46	573			0	573		573	30	0	0	172	401
47	4,881,786	3,570,990		8,100	8,444,676	1,781,445	6,663,231	8	0	0	533,058	7,911,618
50	33,393	40,865		0	74,258	20,433	53,825	55	0	0	29,604	44,654
1		83,776		0	83,776	41,888	41,888	6	0	0	2,513	81,263
Totals	33,017,024	4,484,798		20,860	37,480,962	2,231,970	35,248,992				2,235,888	35,245,074

Note 1. 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) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

The taxpayer elects to have 2008 building additions in a separate class 1.

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Ontario Cumulative Eligible Capital Deduction
Schedule 10 Page 1 of 2

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
...LDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)* . . . . . = + 319,012 **A**

Add: Cost of eligible capital property acquired during the taxation year + _____ **B**

Other adjustments . . . . . + _____ **C**

B + C . . . . . = _____ x 3 / 4 = _____ **D**

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 . . . . . _____ x 1 / 2 = – _____ **E**

D minus E *(if negative, enter zero)* . . . . . = _____ ▷ + _____ **F**

Amount transferred on amalgamation or wind-up of subsidiary . . . . . + _____ **G**

Subtotal A + F + G . . . . . = 319,012 **H**

Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . + _____ **I**

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada) . . . . . + _____ **J**

Other adjustments . . . . . + _____ **K**

I + J + K . . . . . = _____ x 3 / 4 . . . . . = – _____ **L**

Ontario cumulative eligible capital balance H minus L . . . . . = 319,012 **M**

*If M is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.*

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . . _____ **N**

From **M** 319,012

From **N** – _____

Current year deduction **M minus N** . . . . . = 319,012 x 7 % = + 22,331 **O**

N + O . . . . . = 22,331 ▷ – 22,331 **P**

Note: *The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

Enter amount in box 651 *of the CT23*

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)* . . . . . = 296,681 **Q**

See page 2 - Part 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
[illegible]LDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.* . . . . . R

Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988 . . . . . + 1

Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA . . . . . + 2

Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988 . . . . . + 3

Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988 . . . . . – 4

Deduct line 4 from line 3 *(if negative, enter zero)* . . . . . = ▷ + 5

Total lines 1 + 2 + 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 **1** 7

Amounts at **Line Z** from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 *(This will be **Line T** in earlier versions of this schedule.)* . . . . . + 8

Total lines 7 + 8 . . . . . = ▷ – 9

Deduct line 9 from line 6 *(if negative, enter zero)* . . . . . = ▷ – S

R minus S *(if negative, enter zero)* . . . . . = T

From Line **5** _____ x 1 / 2 . . . . . = – U

T minus U *(if negative, enter zero)* . . . . . = V

From **V** _____ x 2 / 3 . . . . . = W

Lesser of **R** and **S** . . . . . = + Z

Amount to be included in income W + Z . . . . . =

Ontario

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33 King Street West
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Cooperative Education Tax Credit (CETC)
CT23 Schedule 113

ration's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

Instructions for completing the CETC Claim Form

- Enter the relevant details for each qualifying work placement, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each qualifying work placement.
- Enter the total tax credit claimed on line 192, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
  - The maximum amount of credit that can be claimed in respect of each work placement is $1,000.
- Ensure you have the following documentation (Do not include with the form or tax return.):
  - a letter of certification from the Ontario college, university other post-secondary institution, containing information as specified by the Minister, stating that the student is enrolled in a qualifying education program; or
  - a voucher for leading-edge technology programs, other than an apprenticeship, stating that the educational program meets the definition of a qualifying program in leading-edge technology and that the work performed by that student during the work placement is in a related field.
- The credit is **considered government assistance** and is therefore **to be included in income** in the year the credit is claimed.

Summary of Co-operative Education Tax Credit Claimed

Complete a separate entry for each student work placement which ended during the corporation's taxation year. The tax credit is for co-op work placements and leading-edge technology work placements. A work placement is generally considered to be a full-time work assignment for up to 4 months in duration.

Example: If a corporation, with a December 31, 2001 taxation year end, hires an eligible student from September 1, 2001 until April 30, 2002, this would be considered 2 work placements. The first work placement is September 1, 2001 to December 31, 2001 and would be claimed in the 2001 taxation year. The second placement is January 1, 2002 to April 30, 2002 and must be claimed in the 2002 taxation year.

lifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates (year month day)	Eligible Costs of Placement (ECP)	* Credit Claimed (See notes below) (max. $1,000 per work placement)
MOHAWK COLLEGE BUSINESS ACCOUNTIN	LISA VEURINK	528 501 679	From 2008-05-01 To 2008-08-31	8,896	890
MOHAWK COLLEGE BUSINESS ACCOUNTIN	ROBERT ROBSON	515 990 398	From 2008-09-01 To 2008-12-31	8,364	836
See schedule			From To	27,906	2,791
If insufficient space, attach schedule			**Totals**	5774 45,166	5798 4,517

Transfer to 192 ***on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8***

Note: Enter corporation's salaries & wages paid in the preceding taxation year A $ 2,000,000 •

If A is $600,000 or greater use 10%. If A is $400,000 or less use 15%.

I [ ] is over $400,000 but less than $600,000 use the following formula to calculate the rate:

Rate =.15 – [.05 (From A 2,000,000 • – $400,000) ÷ $200,000]

Indicate rate used: 10.0000 %. ***Credit claimed equals ECP multiplied by rate.**

Cooperative Education Tax Credit (CETC)
CT23 Schedule 113

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
LDIMAND COUNTY HYDRO INC.	7299908	2008-12-31

Qualifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates (year month day)	Eligible Costs of Placement (ECP)	Credit Claimed (max. $1,000 per work placement)
MOHAWK COLLEGE ELECTRICAL ENGINEEI	JEFFREY MILLS	538 024 191	From 2008-05-01 To 2008-08-31	9,697	970
MOHAWK COLLEGE ELECTRICAL ENGINEEI	JEFFREY MILLS	538 024 191	From 2008-09-01 To 2008-12-31	9,697	970
CAMBRIAN COLLEGE ELECTRICAL ENGINEEI	KEVIN SULLIVAN	502 237 597	From 2008-05-01 To 2008-08-31	8,512	851
			From To		
			Totals	27,906	2,791

Exhibit	Tab	Schedule	Appendix	Contents
5 – Cost of Capital and Capital Structure				
	1	1		Overview
		2		Capital Structure
		3		Cost of Debt
		4		Return on Equity

OVERVIEW

The purpose of this Exhibit is to summarize the method and cost of financing Haldimand County Hydro Inc.'s ("HCHI") capital requirements for the 2010 Test year and to support the rate of return on rate base of 6.38% as shown in this exhibit at Tab 1, Schedule 2.

Capital Structure

HCHI has a current (2009) deemed capital structure of 56.7% debt and 43.3% equity as reflected in 2009 rates calculated using the OEB's 2009 IRM model. The current rate of return on equity is 9.00%, consistent with the capital structure and return approved in HCHI's 2006 EDR Rate Decision (RP-2005-0020 / EB-2005-0373) dated April 12, 2006. HCHI is requesting Board approval of a capital structure of 60% debt – 56% long-term and 4% short-term – and 40% equity and including an equity return of 8.01%.

HCHI is requesting this change in deemed capital structure and associated return on equity to comply with the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors*, (the "Cost of Capital Report"), dated December 20, 2006. In the Cost of Capital Report, the OEB deemed a single capital structure for all local distribution companies for rate-making purposes with a split of 60% debt and 40% equity. Details are provided in this Exhibit at Tab 1, Schedule 2. HCHI believes that the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Cost of Debt

- **Long-Term Debt**

  HCHI is requesting a return on long-term debt for the 2010 Test year of 5.58%. Details of HCHI's long-term debt cost are provided in Tab 1, Schedule 3 of this Exhibit.

Long-term debt cost information for the 2006 Board Approved, 2006, 2007, and 2008 Actual, and 2009 Bridge year and 2010 Test year periods are also filed in Tab 1, Schedule 3, Table 2 of this Exhibit.

- **Short-Term Debt**

HCHI is requesting a return on short-term debt for the 2010 Test year of 1.33%, consistent with the *Cost of Capital Parameter Updates for 2009 Cost of Service Applications* issued by the OEB on February 24, 2009. HCHI understands that the OEB will be finalizing the return on short-term debt in early 2010 for rates effective May 1, 2010. HCHI's use of a return on short-term debt of 1.33% is without prejudice to any revisions that may be adopted by the OEB in early 2010.

Return on Equity

HCHI is requesting a return on equity ("ROE") for the 2010 Test year of 8.01% consistent with the *Cost of Capital Parameter Updates for 2009 Cost of Service Applications* issued by the OEB on February 24, 2009. HCHI understands that the OEB will update the return on equity rate in early 2010 for rates effective May 1, 2010. HCHI also understands that the Board has initiated a proceeding to review its policy regarding the cost of capital and any changes to policy made as a result of this review will apply to the setting of rates for the 2010 rate year – the year for which HCHI is currently rebasing. HCHI's use of an ROE of 8.01% is without prejudice to any revised ROE that may be adopted by the OEB in early 2010.

Capital Structure

As discussed in the overview of this Exhibit, HCHI has transitioned its deemed capital structure to the 60% debt and 40% equity ratio for rate-making purposes as determined by the OEB in the Cost of Capital Report noting "…*that a split of 60% debt, 40% equity is appropriate for all distributors*".

HCHI has prepared Table 1 to illustrate its capital structure and component costs, in accordance with the OEB's *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, updated May 27, 2009 (the "Filing Requirements"), for the following years:

- 2006 Board Approved;
- 2006 Actual;
- 2007 Actual;
- 2008 Actual;
- 2009 Bridge year; and
- 2010 Test year.

Cost of Debt and Return on Equity calculations for the 2010 Test year are discussed in the corresponding Schedules and Tables below.

Table 1
Capitalization and Cost of Capital

2006 Board Approved:

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	50.0%	$17,318,690	6.05%	$1,046,961
Short-term Debt		$ -		$ -
Total Debt	50.0% (1)	$17,318,690	6.05% (1)	$1,046,961
Equity				
Common Equity	50.0%	$17,318,690	9.00%	$1,558,682
Preferred Shares		$ -		$ -
Total Equity	50.0% (1)	$17,318,690	9.00% (1)	$1,558,682
Total	100.0%	$34,637,381 (1)	7.52% (1)	$2,605,643

Notes
(1) As approved in HCHI's 2006 EDR rate application.

2006 Actual Year:

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	50.0%	$17,263,595	6.39% (2)	$1,103,441
Short-term Debt		$ -		$ -
Total Debt	50.0% (1)	$17,263,595	6.39%	$1,103,441
Equity				
Common Equity	50.0%	$17,263,595	9.00%	$1,553,724
Preferred Shares		$ -		$ -
Total Equity	50.0% (1)	$17,263,595	9.00% (1)	$1,553,724
Total	100.0%	$34,527,190	7.70%	$2,657,165

Notes
(1) As approved in HCHI's 2006 EDR rate application.
(2) Actual Long-Term Debt Cost as calculated in Table 2.

2007 Actual Year:

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	50.0%	$17,733,261	6.45% (2)	$1,144,083
Short-term Debt		$ -		$ -
Total Debt	50.0% (1)	$17,733,261	6.45%	$1,144,083
Equity				
Common Equity	50.0%	$17,733,261	9.00%	$1,595,993
Preferred Shares		$ -		$ -
Total Equity	50.0% (1)	$17,733,261	9.00% (1)	$1,595,993
Total	100.0%	$35,466,521	7.73%	$2,740,076

Notes
(1) As approved in HCHI's 2006 EDR rate application.
(2) Actual Long-Term Debt Cost as calculated in Table 2.

2008 Actual Year:

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	53.3%	$19,604,739	6.42% (2)	$1,258,183
Short-term Debt		$ -		$ -
Total Debt	53.3% (3)	$19,604,739	6.42%	$1,258,183
Equity				
Common Equity	46.7%	$17,177,136	9.00%	$1,545,942
Preferred Shares		$ -		$ -
Total Equity	46.7% (3)	$17,177,136	9.00% (1)	$1,545,942
Total	100.0%	$36,781,875	7.62%	$2,804,125

Notes
(1) As approved in HCHI's 2006 EDR rate application.
(2) Actual Long-Term Debt Cost as calculated in Table 2.
(3) As approved in HCHI's 2008 IRM rate application.

2009 Bridge Year:

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.7%	$22,118,207	5.88% (2)	$1,299,631
Short-term Debt		$ -		$ -
Total Debt	56.7% (3)	$22,118,207	5.88%	$1,299,631
Equity				
Common Equity	43.3%	$16,890,976	9.00%	$1,520,188
Preferred Shares		$ -		$ -
Total Equity	43.3% (3)	$16,890,976	9.00% (1)	$1,520,188
Total	100.0%	$39,009,183	7.23%	$2,819,819

Notes
(1) As approved in HCHI's 2006 EDR rate application.
(2) Actual Long-Term Debt Cost as calculated in Table 2.
(3) As approved in HCHI's 2009 IRM rate application.

2010 Test Year:

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.0%	$22,454,351	5.58% (2)	$1,253,729
Short-term Debt	4.00%	$1,603,882	1.33% (3)	$21,332
Total Debt	60.0% (1)	$24,058,233	5.30%	$1,275,060
Equity				
Common Equity	40.0%	$16,038,822	8.01%	$1,284,710
Preferred Shares		$ -		$ -
Total Equity	40.0% (1)	$16,038,822	8.01% (3)	$1,284,710
Total	100.0%	$40,097,056	6.38%	$2,559,770

Notes
(1) As per "Report of the Board on Cost of Capital" for Electricity Distributors.
(2) Actual Long-Term Debt Cost as calculated in Table 2.
(3) As per "Cost of Capital Parameter" update for 2009 Cost of Service Rate Applications.

1

COST OF DEBT

Long-Term Debt

In the Cost of Capital Report, the OEB established policies with respect to long-term debt. All of HCHI's long-term debt is third party debt, with a component as embedded debt and a component as new debt. The OEB's report established embedded debt as "*long-term debt at rates that differ according to when the debt was incurred*". (Debt incurred at time when assets put in-service and the cost of the debt is at prevailing market rates.)

The Board determined that for embedded debt the rate approved in prior OEB decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.

For new third party debt, the OEB determined the rate will be a prudently negotiated contracted rate and would include recognition of premiums and discounts.

Table 2 below provides details of the long-term debt held by third parties in each of the 2006 Board Approved, 2006, 2007, and 2008 Actual, 2009 Bridge year, and the 2010 Test year and the weighted cost of each year's debt.

Short-Term Debt

As discussed in the overview, HCHI has used a short-term debt rate for the 2010 Test year of 1.33% consistent with the *Cost of Capital Parameter Updates for 2009 Cost of Service Applications* issued by the OEB on February 24, 2009. In the Cost of Capital Report the OEB confirmed its determination that "*short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors*". The short-term debt amount will be fixed at 4% of rate base. In the 2010 Test year in Table 1 above, it can be noted that HCHI has used a short-term debt rate of 1.33% calculated on 4% of rate base.

Table 2
Long-Term Debt Details and Weighted Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Debenture - HHEC	Haldimand County	N	May 1, 2000	9,930,000	10	6.40%	BA2006	635,520
Debenture - DHEC	Haldimand County	N	July 2, 1999	3,737,000	10	6.00%	BA2006	224,220
Term Loan	CIBC	N	December 21, 2001	1,400,000	10	3.65%	BA2006	51,100
Debenture - HHEC	Haldimand County	N	May 1, 2000	9,250,000	10	6.54%	2006	604,950
Debenture - DHEC	Haldimand County	N	July 2, 1999	3,298,000	10	6.38%	2006	210,412
Term Loan	CIBC	N	December 21, 2001	1,100,000	10	5.18%	2006	56,980
Debenture - HHEC	Haldimand County	N	May 1, 2000	8,810,000	10	6.55%	2007	577,055
Debenture - DHEC	Haldimand County	N	July 2, 1999	2,986,500	10	6.44%	2007	192,331
Term Loan	CIBC	N	December 21, 2001	900,000	10	5.53%	2007	49,745
Debenture - HHEC	Haldimand County	N	May 1, 2000	8,340,000	10	6.56%	2008	547,104
Debenture - DHEC	Haldimand County	N	July 2, 1999	2,655,500	10	6.52%	2008	173,139
Term Loan	CIBC	N	December 21, 2001	700,000	10	4.34%	2008	30,345
Debenture - HHEC	Haldimand County	N	May 1, 2000	7,840,000	10	6.57%	2009	515,088
Debenture - DHEC	Haldimand County	N	July 2, 1999	1,242,500	10	6.13%	2009	76,165
Debenture	Infrastructure Ontario	N	December 1, 2009	81,417	5	0.00%	2009	0
Debenture	Infrastructure Ontario	N	December 1, 2009	21,909	10	0.00%	2009	0
Debenture	Infrastructure Ontario	N	December 1, 2009	333,333	15	0.00%	2009	0
Debenture	Infrastructure Ontario	N	December 1, 2009	423,652	25	0.00%	2009	0
Term Loan	CIBC	N	December 21, 2001	500,000	10	4.47%	2009	22,350
Debenture - HHEC	Haldimand County	N	May 1, 2000	2,556,667	10	9.75%	2010	249,275
Debenture	Infrastructure Ontario	N	December 1, 2009	911,867	5	4.45%	2010	40,578
Debenture	Infrastructure Ontario	N	December 1, 2009	254,144	10	4.41%	2010	11,208
Debenture	Infrastructure Ontario	N	December 1, 2009	3,911,111	15	4.98%	2010	194,773
Debenture	Infrastructure Ontario	N	December 1, 2009	5,016,038	25	5.53%	2010	277,387
Debenture	Infrastructure Ontario	N	May 3, 2010	4,415,326	25	4.14%	2010	182,794
Term Loan	CIBC	N	December 21, 2001	300,000	10	4.52%	2010	13,560
			2006 (Board Approved) Total Long Term Debt	15,067,000	**Total Interest Cost for 2006 (BA)**			910,840
					***N*eighted Debt Cost Rate for 2006 (BA**			6.05%
			2006 Total Long Term Debt	13,648,000	**Total Interest Cost for 2006**			872,342
					Weighted Debt Cost Rate for 2006			6.39%
			2007 Total Long Term Debt	12,696,500	**Total Interest Cost for 2007**			819,130
					Weighted Debt Cost Rate for 2007			6.45%
			2008 Total Long Term Debt	11,695,500	**Total Interest Cost for 2008**			750,588
					Weighted Debt Cost Rate for 2008			6.42%
			2009 Total Long Term Debt	10,442,811	**Total Interest Cost for 2009**			613,603
					Weighted Debt Cost Rate for 2009			5.88%
			2010 Total Long Term Debt	17,365,153	**Total Interest Cost for 2010**			969,576
					Weighted Debt Cost Rate for 2010			5.58%

RETURN ON EQUITY

As indicated in the Overview section of this Exhibit, HCHI is requesting a ROE for the 2010 Test year of 8.01% consistent with the *Cost of Capital Parameter Updates for 2009 Cost of Service Applications* issued by the OEB on February 24, 2009.

HCHI understands that the OEB will update the return on equity rate in early 2010 for rates effective May 1, 2010.

It is also understood that the Board has initiated a proceeding to review its policy regarding the cost of capital and any changes to policy made as a result of this review will apply to the setting of rates for the 2010 rate year.

Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency				
	1	1		Revenue Deficiency - Overview

REVENUE DEFICIENCY – OVERVIEW

The information in this Exhibit supports Haldimand County Hydro Inc.'s ("HCHI") request in this application for an increase in its Revenue Requirement. HCHI requires this increase in order to implement its capital and operating budgets for 2010, so that it can continue to provide a safe and reliable supply of electricity to its customers, earn the permitted ROE and the amount required to service its debt, and to pay its deemed PILs.

HCHI has provided detailed calculations supporting its 2010 revenue deficiency, net of electricity price differentials, as required in the Filing Guidelines – in the details contained within the variance analysis provided in Exhibit 2 – Rate Base and the cost drivers explained in Exhibit 4 – Operating Costs. HCHI's net revenue deficiency is $1,093,610 and when grossed up for PILs, HCHI's revenue deficiency is $1,584,943. As indicated in Exhibit 5, Tab 1, Schedules 1 and 4, HCHI is requesting a rate of return of 8.01% on 40% of the requested rate base of $40,097,055 (see Exhibit 2, Tab 1, Schedule 1 for detailed calculations). HCHI would only earn a rate of return of 1.19% if revenues remained at the 2009 approved rates calculated on the 2010 forecasted load, thus generating the revenue deficiency. The Capital and OM&A variances from the last actual year, 2008, to the 2009 Bridge year and the 2010 Test year have been detailed and discussed in previous Exhibit 2 – Rate Base, and Exhibit 4 – Operating Costs.

Table 1 on the following page provides the "Calculation of Revenue Deficiency" for the 2010 Test year at Existing 2009 OEB-approved rates and the 2010 Test year Revenue Requirement of $13,938,976. This information is a direct insertion of worksheet 5 "Revenue Sufficiency/Deficiency" from the OEB's required "Revenue Requirement Work Form" model (also filed with this application). The model includes worksheet 3 "Taxes/PILs", which calculates the PILs/Tax Provision in the amount of $741,703 – identical to the amount calculated by the OEB's tax model and referred to in Exhibit 4, Tab 3, Schedule 1. In order to reconcile the Revenue Deficiency/Sufficiency worksheet's "Income Tax on Taxable Income of $743,880", to this "PILs/Tax Provision

of $741,703", you must deduct the Income Tax Credits of $21,000 and add the Capital Taxes of $18,823 (i.e. $743,880 – $21,000 + $18,823 = $741,703).

Table 1
Calculation of Revenue Deficiency

	2010 Test Year Existing Rates	2010 Test Year Proposed Rates
Revenue		
Sufficiency / Deficiency from Below		1,584,943
Distribution Revenue	11,238,700	11,238,700
Other Operating Revenue Offsets (Net)	1,115,334	1,115,334
Total Revenue	12,354,034	13,938,976
Distribution Costs		
Operation, Maintenance, and Administration	7,651,970	7,651,970
Depreciation & Amortization	2,932,087	2,932,087
Property & Capital Taxes	72,270	72,270
Deemed Interest Expense	1,275,060	1,275,060
Total Costs and Expenses	11,931,387	11,931,387
Utility Income Before Income Taxes	422,647	2,007,590
Tax Adjustments to Accounting Income	392,023	392,023
Taxable Income	814,670	2,399,613
Income Tax Rate	31.0%	31.0%
Income Tax on Taxable Income	252,548	743,880
Income Tax Credits	(21,000)	(21,000)
Utility Net Income	191,099	1,284,710
Utility Rate Base	40,097,055	40,097,055
Equity %	40.00%	40.00%
Equity Component of Rate Base	16,038,822	16,038,822
Income / Equity Rate Base %	1.19%	8.01%
Target Return - Equity on Rate Base	8.01%	8.01%
Target Return on Equity	1,284,710	1,284,710
Revenue Deficiency	1,093,610	
Gross Revenue Deficiency	1,584,943	

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1	1		Cost Allocation Overview
		2		2010 Cost Allocation Updates
		3		Summary of Results and Proposed Changes
			A	2010 Test Year Cost Allocation Model
			B	2007 Cost Allocation Filing - Sheet O1 “Revenue to Cost Ratios”

COST ALLOCATION – OVERVIEW

On September 15, 2006, the OEB 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. Haldimand County Hydro Inc. ("HCHI") prepared a cost allocation information filing consistent with HCHI's understanding of the Directions, the Guidelines, the Model and the Instructions. HCHI submitted this filing to the OEB on February 28, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization by one rate class for another. The cost allocation study focused on distribution costs and whether or not the utility's distribution rates by class were collecting the cost of providing distribution service to that corresponding rate class.

For purposes of this 2010 rate application, HCHI has completed an updated cost allocation study using the Board's methodology and model provided in 2006. HCHI's cost allocation study reflects the 2010 forecasted load information by rate class, 2010 forecasted customer and meter information, and the 2010 forecasted costs detailed by USoA account. The transformer ownership allowance has been excluded from the 2010 Cost Allocation model as required by the Guidelines due to the limitations of the OEB's Model with respect to the treatment of the transformer ownership allowance. Further details of information used in the updated 2010 cost allocation model are provided in this Exhibit at Tab 1, Schedule 2.

HCHI has included the updated model to reflect 2010 Test year information in excel format as part of this 2010 rate application filing as a requirement in the updated filing guidelines published May 27, 2009.

2010 COST ALLOCATION UPDATES

As commented on in the Overview section, HCHI has updated the OEB's 2006 Model with data for the 2010 test year on all input worksheets. The data used is consistent with the 2010 test year information that forms part of this 2010 rate application. Inputs into the trial balance represent 2010 cost information; 2010 forecasted assets were broken out into primary and secondary distribution functions, as well as for capital contributions, amortization, and accumulated amortization; meter reading and meter capital information has been updated for 2010 data; 2010 forecasted customer information has been included; and the load profile previously generated by Hydro One Networks Inc. ("HONI") on behalf of HCHI has been updated for 2010 load information.

HCHI has incorporated the "new proposed" rate class, Embedded Distributor – Hydro One Networks Inc., into the updated Model in order to generate a distribution wheeling service rate applicable to this rate class. Costs and applicable assets have been allocated on a direct allocation basis using input worksheet "I9 – Direct Allocation". In order to allocate costs associated with this new rate class, HCHI had to proportion HONI's share of costs that are attributable to the assets providing the low voltage services to HONI and all other related costs associated with providing this low voltage service. A utilization factor of the low voltage lines was used based on HONI's consumption (kWh) passing through the low voltage lines as compared to the combined consumption (kWh) of both HCHI and HONI passing through those same lines. One additional factor used to proportion costs was the line length kilometres (km) of HCHI's asset that is providing the low voltage service as a percentage of HCHI's total line length (km) in that same asset class in HCHI's system. HCHI would like to ensure that the existing customer rate classes do not subsidize the "new" Embedded Distributor rate class applicable to HONI by directly allocating those costs and portion of assets associated with providing the low voltage service to HONI. This direct allocation removes those costs and assets from the mix that is allocated to the balance of HCHI's customer rate classes. This format follows the guidelines and schedule that formed part

of the 2006 EDR Handbook for the calculation of Low Voltage / Wheeling distribution rates.

Transformer ownership allowance has been excluded from the 2010 cost allocation model as instructed in the Filing Guidelines. The costs associated with the transformer ownership allowance have been removed from the revenue requirement in worksheet "I3 Trial Balance Data" and from the approved revenue of the affected rate class, G/S 50 to 4999 kW, in worksheet "I6 – Customer Data".

HCHI's 2010 Updated Cost Allocation Model has been filed as Appendix A to this Exhibit.

SUMMARY OF RESULTS AND PROPOSED CHANGES

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 the rate classification as 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 that the rate classification is over-contributing and is subsidizing other classes of customers.

Table 1 below outlines the comparison of revenue to cost ratios for each customer class as follows:

1. Cost Allocation Informational Filing submitted by HCHI February 28, 2007 (2004 historical data as filed in the 2006 EDR rate application);

2. Cost Allocation Informational Filing as in #1, with the adjustments to exclude transformer ownership allowance; and

3. 2010 Updated Cost Allocation Model (including the adjustment for the transformer ownership).

Table 1
Revenue to Cost Ratios

Customer Class	(1) From Cost Allocation Model Filed 2007 (2004 Historical Data)	(2) Column 1 "Revised" (Exclude Transformer Ownership Allowance)	(3) Cost Allocation Model Results for Test Year (2010)	**(4) Proposed Cost Allocation for Test Year (2010)**	**(5) Proposed Cost Allocation for Rate Year Two (2011)**	(6) Board Target Range
Residential	98.09	99.07	101.01	**101.01**	**101.01**	85 - 115
G/S < 50 kW	101.15	102.13	103.44	**103.44**	**103.44**	80 - 120
G/S 50 to 4999 kW	158.93	150.27	137.67	**114.08**	**102.56**	80 - 180
Sentinel Lights	11.83	11.98	16.76	**43.38**	**70.00**	70 - 120
Street Lighting	18.69	18.94	22.77	**46.38**	**70.00**	70 - 120
Unmetered Scattered Load	71.04	71.35	82.51	**82.51**	**82.51**	80 - 120
Embedded Distributor - Hydro One Networks Inc.			0.33	**100.00**	**100.00**	

On November 28, 2007, the OEB issued its *Report on Application of Cost Allocation for Electricity Distributors* (the "Cost Allocation Report"). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios, which are summarized in Table 1 above in column 6. HCHI has provided output worksheet "O1 – Revenue to Cost Ratios" as originally filed February 28, 2007 and as adjusted for transformer ownership allowance as Appendix B to this Exhibit in order to support columns 1 and 2 in Table 1 above. Refer to Appendix A for 2010 Test year revenue to cost ratios.

In all three cost allocation models, columns 1, 2, and 3, the revenue to cost ratios show that cross-subsidization is occurring. The Sentinel Lights and Street Lighting rate classes have been highly under contributing while the G/S 50 to 4999 kW rate class has been the main over contributor to offset those two rate classes' under contribution. Column 4 reflects the adjustment required to revenue in the 2010 test year to re-align the revenue to cost ratios and reduce some of the cross subsidization. The re-alignment will move those classes that are under contributing, to approximately 50% between their current ratio and the lower limit of the target ratio. For example the current revenue to cost ratio for street lights is 22.77% and moving the ratio to 46.38% means the proposed ratio is half-way between 22.77% and 70% - the 70% being the

low end of the OEB target range. HCHI is also proposing in rate year two, 2011, to further move the under contributing rate classes by the remaining 50% to the bottom of the target ratio as shown in column 5 of Table 1.

The additional revenue from the under contributing class will be distributed to the G/S 50 to 4999 kW rate class that has been over contributing; that is, the class with the highest level of over contribution. This reallocation will occur in the 2010 test year, as well as in rate year two 2011, to offset the adjustment to the under contributing rate classes in both of these same years.

HCHI did not adjust the revenue to cost ratios of the Residential and G/S < 50 kW as their ratios were fairly close to 100% with revenue collected from those two rate classes is covering their costs.

The following table outlines the revenue impacts by rate class in order to achieve the proposed revenue to cost ratios.

Table 2
2010 Test Year Revenue Impacts (Excluding Transformer Ownership Allowance)

Customer Class	2010 Distribution Revenue at 2009 Approved Rates	2010 Test Year Revenue Assuming Current Revenue to Cost Ratios	2010 Test Year Revenue Assuming Proposed Revenue to Cost Ratios	% of Revenue Collected from Each Rate Class
Residential	7,618,229	8,692,594	8,692,594	67.79%
G/S < 50 kW	1,851,407	2,112,502	2,112,502	16.47%
G/S 50 to 4999 kW	1,654,637	1,887,983	1,548,436	12.07%
Sentinel Lights	17,232	19,662	74,483	0.58%
Street Lighting	77,194	88,080	199,036	1.55%
Unmetered Scattered Load	20,001	22,822	22,822	0.18%
Embedded Distributor				
- Hydro One Networks Inc.	0	0	173,771	1.36%
	11,238,700	12,823,643	12,823,644	100.00%

The 2007 Cost Allocation Study also discussed the treatment of the fixed rate component; that is, the monthly distribution service charge rate as well as metering

credits for the Unmetered Scattered Load ("USL") rate class. In the Model, a lower and upper boundary was set by the distributor for the monthly service charge. The lower boundary being the floor or minimum represented by avoided costs; that is, costs that are not subject to other cost allocation judgments (meter-related costs and billing and collecting costs). The upper boundary being the ceiling or maximum based on the avoided costs plus customer related distribution system costs; that is, the allocated customer costs from the cost allocation model. In addition to the upper and lower boundaries of the monthly service charge, the Model also calculated a metering credit for the USL rate class specific to each distributor's metering cost for the G/S < 50 kW rate class.

Table 3 below shows HCHI's existing 2009 OEB-approved monthly service charges (exclusive of smart meter funding adder) by rate class, the floor and ceiling for the monthly service charge, and the metering credit for USL calculated from HCHI's cost allocation model, and the "proposed" monthly service charge for the 2010 Test year.

Table 3
Monthly Service Charge

Customer Class	2009 Base Rates From OEB Approved Tariff	Avoided Cost (Floor) from 2010 Cost Allocation Filing	Minimum System with PLCC Adustment (Ceiling) from 2010 Cost Allocation Filing	G/S < 50 kW Metering Unit Cost ($ / Customer / Month)	"Proposed" Monthly Service Charge for 2010 Test Year
Residential	11.01	4.06	28.02		20.76
G/S < 50 kW	18.07	9.55	37.41		29.37
G/S 50 to 4999 kW	33.65	55.50	105.91		105.91
Sentinel Lights	1.71	2.44	27.95		7.39
Street Lighting	1.51	-0.00	24.25		3.89
Unmetered Scattered Load	9.03	1.75	24.58	(8.46)	20.91
Embedded Distributor - Hydro One Networks Inc.		144.77	191.77		191.77

HCHI is proposing to move the G/S 50 to 4999 kW rate class to the ceiling of the monthly service charge as calculated in the 2010 cost allocation model. As shown in the 2009 existing rate column, this rate class' monthly service charge is well below the

floor for the particular rate class. HCHI would like to take this opportunity to move this rate class' monthly service charge to ensure customer related costs are covered by the appropriate revenue mechanism. The bill impact will be minimal, if any, because this adjustment is being offset by the adjustment in the revenue to cost ratio for this rate class as shown in Table 1 above.

Table 3 also provides the monthly service charge calculation from the 2010 cost allocation model for the "new" rate class, Embedded Distributor – Hydro One Networks Inc. HCHI is also proposing the "new" rates for this class be split between a variable and fixed component using the cost allocation model's ceiling calculation as the "proposed" monthly service charge for this "new" rate class.

HCHI is also proposing to adjust the USL rate class' monthly service charge to better represent the costs associated with that rate class. HCHI feels that to service the USL customer loads versus small general service customer loads only differs by a small material cost. Therefore, HCHI is proposing to adjust the USL monthly service charge to that of the G/S < 50 kW rate class less the metering credit calculated in the 2010 cost allocation model. This metering credit recognizes that HCHI avoids the costs associated with meter management when providing service to this customer class yet incurs the balance of costs associated with the small General Service customer.

For the Residential and G/S < 50 kW rate classes, the monthly service charge was determined in HCHI's proposal to alter the fixed / variable revenue proportions for these two classes based on an analysis HCHI prepared against its peer grouping. This is discussed in detail in Exhibit 8, Tab 1, Schedule 1. The monthly service charge for both of these rate classes still remain between the floor and ceiling generated by the cost allocation model updated with 2010 data.

HCHI proposes a monthly service charge for the Sentinel Lights and Street Lighting rate classes based on the current fixed / variable revenue proportion applicable to each rate class. The fixed component of the distribution charge is calculated by dividing the fixed

distribution portion of the base revenue requirement by the appropriate 2010 Test year annualized connection number. These calculations are detailed in Exhibit 8, Tab 1, Schedule 1.

As already noted, all of the above items are discussed further in Exhibit 8 with relevant bill impacts.

Cost Allocation Summary

The discussion and Tables above support HCHI's proposed reallocation of distribution revenues across customer classes, in order to begin moving toward revenue to cost ratios of 100% and reduce cross-subsidization. HCHI submits that the proposed reallocation of distribution revenue is fair and reasonable for the following reasons:

- Customer class revenues will more closely reflect the actual costs of providing distribution service to that class;
- The reallocation to the Street Lighting and Sentinel Lights customer rate classes continues into 2011 with proposed offsets to the G/S 50 to 4999 kW rate class;
- Allocation of direct costs associated with the "new" Embedded Distributor rate class applicable to Hydro One Networks Inc. will avoid other customer rate classes subsidizing this class;
- Treats the Unmetered Scattered Load customer rate class appropriately as a small general service load with a credit for costs associated with meter management; and
- Moves the monthly service charge for certain rate classes to ensure avoided costs and customer related distribution costs are recovered through the appropriate distribution revenue mechanism.

Ontario Energy Board

2010 COST ALLOCATION STUDY

Sheet I1 Utility Information Sheet

Name of LDC:	HALDIMAND COUNTY HYDRO INC.			
License Number:	ED-2002-0539			
2010 EDR EB Number:	EB-2009-0265	**Cost Allocation EB Number:**		⟸ drop-down menu
Date of Submission:	Friday, August 28, 2009	**Version:**	1.2	

Contact Information

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2010 COST ALLOCATION STUDY
HALDIMAND COUNTY HYDRO INC.
EB-2009-0265
Friday, August 28, 2009
Sheet I2 Class Selection - First Run 2010 Cost of Service Rat

Instructions:
Step 1: Pleae input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

Click for Drop-Down Menu →

First Run	If desired, provide a summary of this run (40 characters max.)
	2010 Cost of Service Rate Application

		Utility's Class Definition	Current
1	Residential	Residential	YES
2	GS <50	General Service less than 50 kW	YES
3	GS>50-Regular	General Service 50 to 4,999 kW	YES
4	GS> 50-TOU		NO
5	GS >50-Intermediate		NO
6	Large Use >5MW		NO
7	Street Light	Street Lighting	YES
8	Sentinel	Sentinel Lighting	YES
9	Unmetered Scattered Load	Unmetered Scattered Load	YES
10	Embedded Distributor	Embedded Distributor - Hydro One	YES
11	Rate Class 1		NO
12	Rate class 2		NO
13	Rate class 3		NO
14	Rate class 4		NO
15	Rate class 5		NO
16	Rate class 6		NO
17	Rate class 7		NO
18	Rate class 8		NO
19	Rate class 9		NO
20	Rate class 10		NO

Update

** Space available for additional information about this run

2010 COST ALLOCATION STUDY

HALDIMAND COUNTY HYDRO INC.

EB-2009-0265

Friday, August 28, 2009

Sheet I3 Trial Balance Data - First Run 2010 Cost of Service Rate Application

Instructions:

Step 1: Copy 2010 Trial Balance values (Trial Balance Sheet-Revenue Req't Model) to Column D21 of this worksheet. Use the Edit - *Paste Special - Values* function.

Step 2: Enter the amounts needed to be reclassified to column F.

Step 3: Enter Target Net Income from Revenue Req't Model (Return on Capital Sheet)

Step 4: Enter PILs from 2010 Rate Application (Capital Tax & Expense Schedule Sheet)

Step 5: Enter Interest from Reveneu Req't Model (Return on Capital Sheet)

Step 6: Enter specific service charges offset from Revenue Req't Model (2010 Income Statement Sheet)

Step 7: Enter Transformation Ownership Allowance Credit from Revenue Req't Model (DO NOT INPUT-per Bruce Bacon)

Step 8: Enter Low Voltage Wheeling Adjustment Credit from Revenue Req't Model (DO NOT INPUT-per Bruce Bacon)

Step 9: Enter Revenue Requirement for 2010 Rate Application (Revenue Req't Sheet)

Step 10: Enter Total Rate Base from Revenue Req't Model (Return on Capital Sheet)

Step 11: Enter Directly Allocated amounts into column G.

→	**Approved Target Net Income ($)**	$1,284,710		
→	**Approved PILs ($)**	$741,703		
→	**Approved Interest ($)**	$1,275,060		
→	**Approved Specific Service Charges ($)**	$212,558		
→	**Approved Transformer Ownership Allowance ($)**			
→	**Approved Low Voltage Wheeling Adjustment ($)**			
→	**Approved Revenue Requirement ($)**	$13,938,976	**From this Sheet**	**Differences?**
	Revenue Requirement to be Used in this model ($)	$13,938,976	**$13,938,977**	**Rev Req Matches**
→	**Approved Rate Base ($)**	$40,097,055		
	Rate Base to be Used in this model ($)	$40,097,055	**$40,097,055**	**Rate Base Matches**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts		Financial Statement (2010 Test Year)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash		$0				$0
1010	Cash Advances and Working Funds		$0				$0
1020	Interest Special Deposits		$0				$0
1030	Dividend Special Deposits		$0				$0
1040	Other Special Deposits		$0				$0
1060	Term Deposits		$0				$0
1070	Current Investments		$0				$0
1100	Customer Accounts Receivable		$0				$0
1102	Accounts Receivable - Services		$0				$0
1104	Accounts Receivable - Recoverable Work		$0				$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.		$0				$0
1110	Other Accounts Receivable		$0				$0
1120	Accrued Utility Revenues		$0				$0
1130	Accumulated Provision for Uncollectible Accounts--Credit		$0				$0
1140	Interest and Dividends Receivable		$0				$0
1150	Rents Receivable		$0				$0
1170	Notes Receivable		$0				$0
1180	Prepayments		$0				$0
1190	Miscellaneous Current and Accrued Assets		$0				$0
1200	Accounts Receivable from Associated Companies		$0				$0
1210	Notes Receivable from Associated Companies		$0				$0
1305	Fuel Stock		$0				$0
1330	Plant Materials and Operating Supplies		$0				$0
1340	Merchandise		$0				$0
1350	Other Materials and Supplies		$0				$0
1405	Long Term Investments in Non-Associated Companies		$0				$0
1408	Long Term Receivable - Street Lighting Transfer		$0				$0
1410	Other Special or Collateral Funds		$0				$0
1415	Sinking Funds		$0				$0

1425	Unamortized Debt Expense		$0			$0
1445	Unamortized Discount on Long-Term Debt--Debit		$0			$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses		$0			$0
1460	Other Non-Current Assets		$0			$0
1465	O.M.E.R.S. Past Service Costs		$0			$0
1470	Past Service Costs - Employee Future Benefits		$0			$0
1475	Past Service Costs - Other Pension Plans		$0			$0
1480	Portfolio Investments - Associated Companies		$0			$0
1485	Investment in Associated Companies - Significant Influence		$0			$0
1490	Investment in Subsidiary Companies		$0			$0
1505	Unrecovered Plant and Regulatory Study Costs		$0			$0
1508	Other Regulatory Assets		$0			$0
1510	Preliminary Survey and Investigation Charges		$0			$0
1515	Emission Allowance Inventory		$0			$0
1516	Emission Allowances Withheld		$0			$0
1518	RCVARetail		$0			$0
1520	Power Purchase Variance Account		$0			$0
1525	Miscellaneous Deferred Debits		$0			$0
1530	Deferred Losses from Disposition of Utility Plant		$0			$0
1540	Unamortized Loss on Reacquired Debt		$0			$0
1545	Development Charge Deposits/ Receivables		$0			$0
1548	RCVASTR		$0			$0
1560	Deferred Development Costs		$0			$0
1562	Deferred Payments in Lieu of Taxes		$0			$0
1563	Account 1563 - Deferred PILs Contra Account		$0			$0
1565	Conservation and Demand Management Expenditures and Recoveries		$0			$0
1570	Qualifying Transition Costs		$0			$0
1571	Pre-market Opening Energy Variance		$0			$0
1572	Extraordinary Event Costs		$0			$0
1574	Deferred Rate Impact Amounts		$0			$0
1580	RSVAWMS		$0			$0
1582	RSVAONE-TIME		$0			$0
1584	RSVANW		$0			$0
1586	RSVACN		$0			$0
1588	RSVAPOWER		$0			$0
1590	Recovery of Regulatory Asset Balances		$0			$0
1605	Electric Plant in Service - Control Account		$0			$0
1606	Organization		$0			$0
1608	Franchises and Consents		$0			$0
1610	Miscellaneous Intangible Plant		$0			$0
1615	Land		$0			$0
1616	Land Rights		$0			$0
1620	Buildings and Fixtures		$0			$0
1630	Leasehold Improvements		$0			$0
1635	Boiler Plant Equipment		$0			$0
1640	Engines and Engine-Driven Generators		$0			$0
1645	Turbogenerator Units		$0			$0
1650	Reservoirs, Dams and Waterways		$0			$0
1655	Water Wheels, Turbines and Generators		$0			$0
1660	Roads, Railroads and Bridges		$0			$0
1665	Fuel Holders, Producers and Accessories		$0			$0
1670	Prime Movers		$0			$0
1675	Generators		$0			$0
1680	Accessory Electric Equipment		$0			$0
1685	Miscellaneous Power Plant Equipment		$0			$0
1705	Land		$0			$0
1706	Land Rights		$0			$0
1708	Buildings and Fixtures		$0			$0
1710	Leasehold Improvements		$0			$0
1715	Station Equipment		$0			$0
1720	Towers and Fixtures		$0			$0
1725	Poles and Fixtures		$0			$0
1730	Overhead Conductors and Devices		$0			$0
1735	Underground Conduit		$0			$0
1740	Underground Conductors and Devices		$0			$0
1745	Roads and Trails		$0			$0
1805	Land		$0			$0
1806	Land Rights		$0			$0
1808	Buildings and Fixtures		$0			$0
1810	Leasehold Improvements		$0			$0
1815	Transformer Station Equipment - Normally Primary above 50 kV		$0			$0
1820	Distribution Station Equipment - Normally Primary below 50 kV		$580,903			$580,903
1825	Storage Battery Equipment		$0			$0
1830	Poles, Towers and Fixtures		$17,141,257		$46,772	$17,094,485
1835	Overhead Conductors and Devices		$9,355,015		$24,464	$9,330,551
1840	Underground Conduit		$790,734			$790,734
1845	Underground Conductors and Devices		$6,811,737			$6,811,737
1850	Line Transformers		$10,699,998			$10,699,998
1855	Services		$2,431,707			$2,431,707
1860	Meters		$2,817,829			$2,817,829
1865	Other Installations on Customer's Premises		$0			$0
1870	Leased Property on Customer Premises		$0			$0
1875	Street Lighting and Signal Systems		$0			$0
1905	Land		$139,071			$139,071
1906	Land Rights		$695,389			$695,389
1908	Buildings and Fixtures		$2,013,342			$2,013,342
1910	Leasehold Improvements		$0			$0
1915	Office Furniture and Equipment		$348,916			$348,916

1920	Computer Equipment - Hardware	$554,984			$554,984
1925	Computer Software	$2,407,443			$2,407,443
1930	Transportation Equipment	$1,908,883			$1,908,883
1935	Stores Equipment	$0			$0
1940	Tools, Shop and Garage Equipment	$535,201			$535,201
1945	Measurement and Testing Equipment	$0			$0
1950	Power Operated Equipment	$0			$0
1955	Communication Equipment	$66,281			$66,281
1960	Miscellaneous Equipment	$0			$0
1965	Water Heater Rental Units	$0			$0
1970	Load Management Controls - Customer Premises	$0			$0
1975	Load Management Controls - Utility Premises	$0			$0
1980	System Supervisory Equipment	$0			$0
1985	Sentinel Lighting Rental Units	$0			$0
1990	Other Tangible Property	$0			$0
1995	Contributions and Grants - Credit	($2,790,019)			($2,790,019)
2005	Property Under Capital Leases	$0			$0
2010	Electric Plant Purchased or Sold	$0			$0
2020	Experimental Electric Plant Unclassified	$0			$0
2030	Electric Plant and Equipment Leased to Others	$0			$0
2040	Electric Plant Held for Future Use	$0			$0
2050	Completed Construction Not Classified--Electric	$0			$0
2055	Construction Work in Progress--Electric	$0			$0
2060	Electric Plant Acquisition Adjustment	$0			$0
2065	Other Electric Plant Adjustment	$0			$0
2070	Other Utility Plant	$0			$0
2075	Non-Utility Property Owned or Under Capital Leases	$0			$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($21,665,503)		($27,368)	($21,638,135)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	($203,615)			($203,615)
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	$0			$0
2160	Accumulated Amortization of Other Utility Plant	$0			$0
2180	Accumulated Amortization of Non-Utility Property	$0			$0
2205	Accounts Payable	$0			$0
2208	Customer Credit Balances	$0			$0
2210	Current Portion of Customer Deposits	$0			$0
2215	Dividends Declared	$0			$0
2220	Miscellaneous Current and Accrued Liabilities	$0			$0
2225	Notes and Loans Payable	$0			$0
2240	Accounts Payable to Associated Companies	$0			$0
2242	Notes Payable to Associated Companies	$0			$0
2250	Debt Retirement Charges(DRC) Payable	$0			$0
2252	Transmission Charges Payable	$0			$0
2254	Electrical Safety Authority Fees Payable	$0			$0
2256	Independent Market Operator Fees and Penalties Payable	$0			$0
2260	Current Portion of Long Term Debt	$0			$0
2262	Ontario Hydro Debt - Current Portion	$0			$0
2264	Pensions and Employee Benefits - Current Portion	$0			$0
2268	Accrued Interest on Long Term Debt	$0			$0
2270	Matured Long Term Debt	$0			$0
2272	Matured Interest on Long Term Debt	$0			$0
2285	Obligations Under Capital Leases--Current	$0			$0
2290	Commodity Taxes	$0			$0
2292	Payroll Deductions / Expenses Payable	$0			$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.	$0			$0
2296	Future Income Taxes - Current	$0			$0
2305	Accumulated Provision for Injuries and Damages	$0			$0
2306	Employee Future Benefits	$0			$0
2308	Other Pensions - Past Service Liability	$0			$0
2310	Vested Sick Leave Liability	$0			$0
2315	Accumulated Provision for Rate Refunds	$0			$0
2320	Other Miscellaneous Non-Current Liabilities	$0			$0
2325	Obligations Under Capital Lease--Non-Current	$0			$0
2330	Development Charge Fund	$0			$0
2335	Long Term Customer Deposits	$0			$0
2340	Collateral Funds Liability	$0			$0
2345	Unamortized Premium on Long Term Debt	$0			$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion	$0			$0
2350	Future Income Tax - Non-Current	$0			$0
2405	Other Regulatory Liabilities	$0			$0
2410	Deferred Gains from Disposition of Utility Plant	$0			$0
2415	Unamortized Gain on Reacquired Debt	$0			$0
2425	Other Deferred Credits	$0			$0
2435	Accrued Rate-Payer Benefit	$0			$0
2505	Debentures Outstanding - Long Term Portion	$0			$0
2510	Debenture Advances	$0			$0
2515	Reacquired Bonds	$0			$0
2520	Other Long Term Debt	$0			$0
2525	Term Bank Loans - Long Term Portion	$0			$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion	$0			$0
2550	Advances from Associated Companies	$0			$0
3005	Common Shares Issued	$0			$0
3008	Preference Shares Issued	$0			$0
3010	Contributed Surplus	$0			$0
3020	Donations Received	$0			$0
3022	Development Charges Transferred to Equity	$0			$0
3026	Capital Stock Held in Treasury	$0			$0
3030	Miscellaneous Paid-In Capital	$0			$0
3035	Installments Received on Capital Stock	$0			$0

3040	Appropriated Retained Earnings		$0			$0
3045	Unappropriated Retained Earnings		$0			$0
3046	Balance Transferred From Income		$0	$0	$1,883	($1,282,827)
3047	Appropriations of Retained Earnings - Current Period		$0			$0
3048	Dividends Payable-Preference Shares		$0			$0
3049	Dividends Payable-Common Shares		$0			$0
3055	Adjustment to Retained Earnings		$0			$0
3065	Unappropriated Undistributed Subsidiary Earnings		$0			$0
4006	Residential Energy Sales		($10,988,302)			($10,988,302)
4010	Commercial Energy Sales		$0			$0
4015	Industrial Energy Sales		$0			$0
4020	Energy Sales to Large Users		$0			$0
4025	Street Lighting Energy Sales		($150,460)			($150,460)
4030	Sentinel Lighting Energy Sales		($27,165)			($27,165)
4035	General Energy Sales		($11,197,854)			($11,197,854)
4040	Other Energy Sales to Public Authorities		$0			$0
4045	Energy Sales to Railroads and Railways		$0			$0
4050	Revenue Adjustment		$0			$0
4055	Energy Sales for Resale		$0			$0
4060	Interdepartmental Energy Sales		$0			$0
4062	Billed WMS		($2,373,264)			($2,373,264)
4075	Billed-LV		($209,412)			($209,412)
4066	Billed NW		($1,955,675)			($1,955,675)
4068	Billed CN		($1,775,798)			($1,775,798)
4080	Distribution Services Revenue		($12,178,622)	$645,021		($12,823,643)
4082	Retail Services Revenues		($34,956)			($34,956)
4084	Service Transaction Requests (STR) Revenues		($1,070)			($1,070)
4090	Electric Services Incidental to Energy Sales		($107,127)			($107,127)
4105	Transmission Charges Revenue		$0			$0
4110	Transmission Services Revenue		$0			$0
4205	Interdepartmental Rents		$0			$0
4210	Rent from Electric Property		($79,358)	$79,358		$0
4215	Other Utility Operating Income		$0			$0
4220	Other Electric Revenues		$0			$0
4225	Late Payment Charges		($319,125)			($319,125)
4230	Sales of Water and Water Power		$0			$0
4235	Miscellaneous Service Revenues		($133,200)	$133,200		($212,558)
4240	Provision for Rate Refunds		$0			$0
4245	Government Assistance Directly Credited to Income		$0			$0
4305	Regulatory Debits		$0			$0
4310	Regulatory Credits		$0			$0
4315	Revenues from Electric Plant Leased to Others		$0			$0
4320	Expenses of Electric Plant Leased to Others		$0			$0
4325	Revenues from Merchandise, Jobbing, Etc.		($10,400)			($10,400)
4330	Costs and Expenses of Merchandising, Jobbing, Etc.		$0			$0
4335	Profits and Losses from Financial Instrument Hedges		$0			$0
4340	Profits and Losses from Financial Instrument Investments		$0			$0
4345	Gains from Disposition of Future Use Utility Plant		$0			$0
4350	Losses from Disposition of Future Use Utility Plant		$0			$0
4355	Gain on Disposition of Utility and Other Property		$0			$0
4360	Loss on Disposition of Utility and Other Property		$0			$0
4365	Gains from Disposition of Allowances for Emission		$0			$0
4370	Losses from Disposition of Allowances for Emission		$0			$0
4375	Revenues from Non-Utility Operations		$0			$0
4380	Expenses of Non-Utility Operations		$0			$0
4385	Non-Utility Rental Income		$0			$0
4390	Miscellaneous Non-Operating Income		($362,550)			($362,550)
4395	Rate-Payer Benefit Including Interest		$0			$0
4398	Foreign Exchange Gains and Losses, Including Amortization		$0			$0
4405	Interest and Dividend Income		($67,548)			($67,548)
4415	Equity in Earnings of Subsidiary Companies		$0			$0
4505	Operation Supervision and Engineering		$0			$0
4510	Fuel		$0			$0
4515	Steam Expense		$0			$0
4520	Steam From Other Sources		$0			$0
4525	Steam Transferred--Credit		$0			$0
4530	Electric Expense		$0			$0
4535	Water For Power		$0			$0
4540	Water Power Taxes		$0			$0
4545	Hydraulic Expenses		$0			$0
4550	Generation Expense		$0			$0
4555	Miscellaneous Power Generation Expenses		$0			$0
4560	Rents		$0			$0
4565	Allowances for Emissions		$0			$0
4605	Maintenance Supervision and Engineering		$0			$0
4610	Maintenance of Structures		$0			$0
4615	Maintenance of Boiler Plant		$0			$0
4620	Maintenance of Electric Plant		$0			$0
4625	Maintenance of Reservoirs, Dams and Waterways		$0			$0
4630	Maintenance of Water Wheels, Turbines and Generators		$0			$0
4635	Maintenance of Generating and Electric Plant		$0			$0
4640	Maintenance of Miscellaneous Power Generation Plant		$0			$0
4705	Power Purchased		$22,363,781			$22,363,781
4708	Charges-WMS		$2,373,264			$2,373,264
4710	Cost of Power Adjustments		$0			$0
4750	Charges-LV		$209,412			$209,412
4714	Charges-NW		$1,955,675			$1,955,675
4715	System Control and Load Dispatching		$0			$0
4716	Charges-CN		$1,775,798			$1,775,798

4720	Other Expenses	$0				$0
4725	Competition Transition Expense	$0				$0
4730	Rural Rate Assistance Expense	$0				$0
4805	Operation Supervision and Engineering	$0				$0
4810	Load Dispatching	$0				$0
4815	Station Buildings and Fixtures Expenses	$0				$0
4820	Transformer Station Equipment - Operating Labour	$0				$0
4825	Transformer Station Equipment - Operating Supplies and Expense	$0				$0
4830	Overhead Line Expenses	$0				$0
4835	Underground Line Expenses	$0				$0
4840	Transmission of Electricity by Others	$0				$0
4845	Miscellaneous Transmission Expense	$0				$0
4850	Rents	$0				$0
4905	Maintenance Supervision and Engineering	$0				$0
4910	Maintenance of Transformer Station Buildings and Fixtures	$0				$0
4916	Maintenance of Transformer Station Equipment	$0				$0
4930	Maintenance of Towers, Poles and Fixtures	$0				$0
4935	Maintenance of Overhead Conductors and Devices	$0				$0
4940	Maintenance of Overhead Lines - Right of Way	$0				$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs	$0				$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails	$0				$0
4960	Maintenance of Underground Lines	$0				$0
4965	Maintenance of Miscellaneous Transmission Plant	$0				$0
5005	Operation Supervision and Engineering	$499,249			$679	$498,570
5010	Load Dispatching	$0				$0
5012	Station Buildings and Fixtures Expense	$0				$0
5014	Transformer Station Equipment - Operation Labour	$0				$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0				$0
5016	Distribution Station Equipment - Operation Labour	$17,889				$17,889
5017	Distribution Station Equipment - Operation Supplies and Expenses	$19,570				$19,570
5020	Overhead Distribution Lines and Feeders - Operation Labour	$120,005			$355	$119,650
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0			$0	$0
5030	Overhead Subtransmission Feeders - Operation	$0			$0	$0
5035	Overhead Distribution Transformers- Operation	$221,961	$0			$221,961
5040	Underground Distribution Lines and Feeders - Operation Labour	$58,608				$58,608
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0				$0
5050	Underground Subtransmission Feeders - Operation	$0				$0
5055	Underground Distribution Transformers - Operation	$15,696	$0			$15,696
5060	Street Lighting and Signal System Expense	$0				$0
5065	Meter Expense	$276,493				$276,493
5070	Customer Premises - Operation Labour	$15,294				$15,294
5075	Customer Premises - Materials and Expenses	$0				$0
5085	Miscellaneous Distribution Expense	$192,883			$137,237	$55,646
5090	Underground Distribution Lines and Feeders - Rental Paid	$0				$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0				$0
5096	Other Rent	$0				$0
5105	Maintenance Supervision and Engineering	$131,689			$177	$131,512
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0				$0
5112	Maintenance of Transformer Station Equipment	$0				$0
5114	Maintenance of Distribution Station Equipment	$107,029				$107,029
5120	Maintenance of Poles, Towers and Fixtures	$607,398			$1,797	$605,601
5125	Maintenance of Overhead Conductors and Devices	$900,963			$2,666	$898,297
5130	Maintenance of Overhead Services	$158,103				$158,103
5135	Overhead Distribution Lines and Feeders - Right of Way	$556,518			$1,647	$554,871
5145	Maintenance of Underground Conduit	$10,687				$10,687
5150	Maintenance of Underground Conductors and Devices	$33,209				$33,209
5155	Maintenance of Underground Services	$111,495				$111,495
5160	Maintenance of Line Transformers	$159,370	$0			$159,370
5165	Maintenance of Street Lighting and Signal Systems	$0				$0
5170	Sentinel Lights - Labour	$0				$0
5172	Sentinel Lights - Materials and Expenses	$0				$0
5175	Maintenance of Meters	$26,272				$26,272
5178	Customer Installations Expenses- Leased Property	$0				$0
5185	Water Heater Rentals - Labour	$0				$0
5186	Water Heater Rentals - Materials and Expenses	$0				$0
5190	Water Heater Controls - Labour	$0				$0
5192	Water Heater Controls - Materials and Expenses	$0				$0
5195	Maintenance of Other Installations on Customer Premises	$0				$0
5205	Purchase of Transmission and System Services	$0				$0
5210	Transmission Charges	$0				$0
5215	Transmission Charges Recovered	$0				$0
5305	Supervision	$144,980				$144,980
5310	Meter Reading Expense	$296,609		$14,980		$311,589
5315	Customer Billing	$602,980				$602,980
5320	Collecting	$254,886				$254,886
5325	Collecting- Cash Over and Short	$0				$0
5330	Collection Charges	$0				$0

5335	Bad Debt Expense	$30,000				$30,000
5340	Miscellaneous Customer Accounts Expenses	$73,968		($14,980)		$58,988
5405	Supervision	$0				$0
5410	Community Relations - Sundry	$28,836				$28,836
5415	Energy Conservation	$18,000				$18,000
5420	Community Safety Program	$0				$0
5425	Miscellaneous Customer Service and Informational Expenses	$0				$0
5505	Supervision	$0				$0
5510	Demonstrating and Selling Expense	$0				$0
5515	Advertising Expense	$0				$0
5520	Miscellaneous Sales Expense	$0				$0
5605	Executive Salaries and Expenses	$71,428				$71,428
5610	Management Salaries and Expenses	$654,364			$901	$653,463
5615	General Administrative Salaries and Expenses	$542,981			$790	$542,191
5620	Office Supplies and Expenses	$112,380			$166	$112,214
5625	Administrative Expense Transferred Credit	$0				$0
5630	Outside Services Employed	$402,106			$582	$401,524
5635	Property Insurance	$19,408			$28	$19,380
5640	Injuries and Damages	$0				$0
5645	Employee Pensions and Benefits	$0				$0
5650	Franchise Requirements	$0				$0
5655	Regulatory Expenses	$101,208			$139	$101,069
5660	General Advertising Expenses	$0				$0
5665	Miscellaneous General Expenses	$57,455	$0		$83	$57,372
5670	Rent	$0				$0
5675	Maintenance of General Plant	$0				$0
5680	Electrical Safety Authority Fees	$0				$0
5685	Independent Market Operator Fees and Penalties	$0				$0
5705	Amortization Expense - Property, Plant, and Equipment	$2,914,312			$3,661	$2,910,651
5710	Amortization of Limited Term Electric Plant	$0				$0
5715	Amortization of Intangibles and Other Electric Plant	$17,775				$17,775
5720	Amortization of Electric Plant Acquisition Adjustments	$0				$0
5725	Miscellaneous Amortization	$0				$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0				$0
5735	Amortization of Deferred Development Costs	$0				$0
5740	Amortization of Deferred Charges	$0				$0
6005	Interest on Long Term Debt	$1,032,383	($1,032,383)		$1,868	$1,273,192
6010	Amortization of Debt Discount and Expense	$0				$0
6015	Amortization of Premium on Debt Credit	$0				$0
6020	Amortization of Loss on Reacquired Debt	$0				$0
6025	Amortization of Gain on Reacquired Debt--Credit	$0				$0
6030	Interest on Debt to Associated Companies	$0				$0
6035	Other Interest Expense	$0				$0
6040	Allowance for Borrowed Funds Used During Construction--Credit	$0				$0
6042	Allowance For Other Funds Used During Construction	$0				$0
6045	Interest Expense on Capital Lease Obligations	$0				$0
6105	Taxes Other Than Income Taxes	$53,447			$83	$53,364
6110	Income Taxes	$571,805	($571,805)		$1,087	$740,616
6115	Provision for Future Income Taxes	($36,748)				($36,748)
6205	Donations	$0				$0
6210	Life Insurance	$0				$0
6215	Penalties	$0				$0
6225	Other Deductions					$0
6305	Extraordinary Income	$0				$0
6310	Extraordinary Deductions	$0				$0
6315	Income Taxes, Extraordinary Items	$0				$0
6405	Discontinues Operations - Income/ Gains	$0				$0
6410	Discontinued Operations - Deductions/ Losses	$0				$0
6415	Income Taxes, Discontinued Operations	$0				$0

$0

Reclassification Equals to Zero. O.K. to Proceed.

Asset Accounts Directly Allocated	$43,868

2006 COST ALLOCATION INFORMATION FILING

HALDIMAND COUNTY HYDRO INC.

EB-2009-0265

Friday, August 28, 2009

Sheet I4 Break Out Worksheet - First Run 2010 Cost of Service Rate Application

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Handbook for detailed instructions*

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)	$34,639,553

RATE BASE AND DISTRIBUTION ASSETS

BALANCE SHEET ITEMS

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
1565	Conservation and Demand Management	$0		-	-					-
1805	Land	$0		$0	-					
1805-1	Land Station >50 kV			$0	-					-
1805-2	Land Station <50 kV		100.00%	$0	-					-
1806	Land Rights	$0		$0	-					
1806-1	Land Rights Station >50 kV			$0	-					-
1806-2	Land Rights Station <50 kV		100.00%	$0	-					-
1808	Buildings and Fixtures	$0		$0	-					
1808-1	Buildings and Fixtures > 50 kV			$0	-					-
1808-2	Buildings and Fixtures < 50 KV		100.00%	$0	-					-
1810	Leasehold Improvements	$0		$0	-					
1810-1	Leasehold Improvements >50 kV			$0	-					-
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0		$0	-					-
1820	Distribution Station Equipment - Normally Primary below 50 kV	$580,903		($580,903)	-					-
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			$0	-					-
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		100.00%	$580,903	580,903			$ (243,414)		337,489
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		0.00%	$0	-					-
1825	Storage Battery Equipment	$0		$0	-					
1825-1	Storage Battery Equipment > 50 kV			$0	-					-
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-					-
1830	Poles, Towers and Fixtures	$17,094,485		($17,094,485)	-					
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-
1830-4	Poles, Towers and Fixtures - Primary		94.00%	$16,068,816	16,068,816	($470,941)	$106,614	$ (6,680,771)		9,023,717

2006 COST ALLOCATION INFORMATION FILING

HALDIMAND COUNTY HYDRO INC.

EB-2009-0265

Friday, August 28, 2009

Sheet I4 Break Out Worksheet - First Run 2010 Cost of Service Rate Application

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Handbook for detailed instructions*

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)	$34,639,553

RATE BASE AND DISTRIBUTION ASSETS

BALANCE SHEET ITEMS

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
1830-5	Poles, Towers and Fixtures - Secondary		6.00%	$1,025,669	1,025,669	($30,060)	$6,805	$ (427,691)		574,723
1835	Overhead Conductors and Devices	$9,330,551		($9,330,551)	-					
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-					-
1835-4	Overhead Conductors and Devices - Primary		89.00%	$8,304,190	8,304,190	($57,586)	$13,366	$ (2,591,749)		5,668,221
1835-5	Overhead Conductors and Devices - Secondary		11.00%	$1,026,361	1,026,361	($7,117)	$1,652	$ (321,274)		699,621
1840	Underground Conduit	$790,734		($790,734)	-					
1840-3	Underground Conduit - Bulk Delivery			$0	-					-
1840-4	Underground Conduit - Primary		85.00%	$672,124	672,124	($168,544)	$33,774	$ (90,672)		446,682
1840-5	Underground Conduit - Secondary		15.00%	$118,610	118,610	($29,743)	$5,960	$ (16,001)		78,826
1845	Underground Conductors and Devices	$6,811,737		($6,811,737)	-					
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-
1845-4	Underground Conductors and Devices - Primary		85.00%	$5,789,976	5,789,976	($747,451)	$159,040	$ (2,436,382)		2,765,183
1845-5	Underground Conductors and Devices - Secondary		15.00%	$1,021,761	1,021,761	($131,903)	$28,066	$ (429,950)		487,974
1850	Line Transformers	$10,699,998		$0	10,699,998	($663,183)	$148,155	$ (3,577,072)		6,607,899
1855	Services	$2,431,707		$0	2,431,707	($399,421)	$70,206	$ (589,147)		1,513,345
1860	Meters	$2,817,829		$0	2,817,829	($84,069)	$16,519	$ (1,018,124)		1,732,155
	Total	**$50,557,944**		**-**	**50,557,944**	**($2,790,019)**	**$590,157**	**($18,422,248)**	**$0**	**29,935,834**
	SUB TOTAL from I3	**$50,557,944**								

2006 COST ALLOCATION INFORMATION FILING

HALDIMAND COUNTY HYDRO INC.

EB-2009-0265

Friday, August 28, 2009

Sheet I4 Break Out Worksheet - First Run 2010 Cost of Service Rate Application

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Handbook for detailed instructions*

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)	$34,639,553

RATE BASE AND DISTRIBUTION ASSETS

BALANCE SHEET ITEMS

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset
1905	Land	$139,071			139,071					$ 139,071
1906	Land Rights	$695,389			695,389				$ (203,615)	$ 491,774
1908	Buildings and Fixtures	$2,013,342			2,013,342			$ (342,078)		$ 1,671,264
1910	Leasehold Improvements	$0			-					$ -
1915	Office Furniture and Equipment	$348,916			348,916			$ (190,833)		$ 158,083
1920	Computer Equipment - Hardware	$554,984			554,984			$ (453,220)		$ 101,764
1925	Computer Software	$2,407,443			2,407,443			$ (1,349,395)		$ 1,058,048
1930	Transportation Equipment	$1,908,883			1,908,883			$ (1,111,558)		$ 797,325
1935	Stores Equipment	$0			-					$ -
1940	Tools, Shop and Garage Equipment	$535,201			535,201			$ (292,679)		$ 242,522
1945	Measurement and Testing Equipment	$0			-					$ -
1950	Power Operated Equipment	$0			-					$ -
1955	Communication Equipment	$66,281			66,281			$ (66,281)		$ -
1960	Miscellaneous Equipment	$0			-					$ -
1970	Load Management Controls - Customer Premises	$0			-					$ -
1975	Load Management Controls - Utility Premises	$0			-					$ -
1980	System Supervisory Equipment	$0			-					$ -
1990	Other Tangible Property	$0			-					$ -
2005	Property Under Capital Leases	$0			-					$ -
2010	Electric Plant Purchased or Sold	$0			-					$ -
Total		$8,669,510		$0	$8,669,510	$0	$0	($3,806,044)	($203,615)	$4,659,851
SUB TOTAL from I3		$8,669,510								
I3 Directly Allocated		$43,868								
Grand Total		$59,271,322		$0	$59,227,454	($2,790,019)	$590,157	($22,228,292)	($203,615)	$34,595,685

2006 COST ALLOCATION INFORMATION FILING

HALDIMAND COUNTY HYDRO INC.

EB-2009-0265

Friday, August 28, 2009

Sheet I4 Break Out Worksheet - First Run 2010 Cost of Service Rate Application

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Handbook for detailed instructions*

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)	$34,639,553

RATE BASE AND DISTRIBUTION ASSETS

BALANCE SHEET ITEMS

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
To be Prorated										
1995	Contributed Capital - 1995	($2,790,019)				$2,790,019	**Balanced**			
2105	Accumulated Depreciation - 2105	($21,638,135)						$21,638,135	**Balanced**	
2120	Accumulated Depreciation - 2120	($203,615)							$203,615	**Balanced**
	Total	**($24,631,769)**								
	Net Assets	**$34,639,553**	**Net Fixed Assets Match 2010 Test Year**							

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$2,910,651
5710	Amortization of Limited Term Electric Plant	$0
5715	Amortization of Intangibles and Other Electric Plant	$17,775
5720	Amortization of Electric Plant Acquisition Adjustments	$0
	Total Amortization Expense	**$2,928,426**

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EB-2009-0265
Friday, August 2
Sheet I4 Break

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Instructions:
This is an input sheet for the Break Out c
***Please see Handbook for detailed instr**

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS			
		5705	5710	5715	5720
Account	Description	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management				
1805	Land				
1805-1	Land Station >50 kV				
1805-2	Land Station <50 kV				
1806	Land Rights				
1806-1	Land Rights Station >50 kV				
1806-2	Land Rights Station <50 kV				
1808	Buildings and Fixtures				
1808-1	Buildings and Fixtures > 50 kV				
1808-2	Buildings and Fixtures < 50 KV				
1810	Leasehold Improvements				
1810-1	Leasehold Improvements >50 kV				
1810-2	Leasehold Improvements <50 kV				
1815	Transformer Station Equipment - Normally Primary above 50 kV				
1820	Distribution Station Equipment - Normally Primary below 50 kV				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)	$20,994			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)				
1825	Storage Battery Equipment				
1825-1	Storage Battery Equipment > 50 kV				
1825-2	Storage Battery Equipment <50 kV				
1830	Poles, Towers and Fixtures				
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery				
1830-4	Poles, Towers and Fixtures - Primary	$750,931			

2006 COST ALLOC
HALDIMAND C
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Friday, August 2
Sheet I4 Break

Ontario

Instructions:
This is an input sheet for the Break Out
Please see Handbook for detailed instr

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS			
		5705	5710	5715	5720
Account	Description	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1830-5	Poles, Towers and Fixtures - Secondary	$48,083			
1835	Overhead Conductors and Devices				
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery				
1835-4	Overhead Conductors and Devices - Primary	$386,738			
1835-5	Overhead Conductors and Devices - Secondary	$47,958			
1840	Underground Conduit				
1840-3	Underground Conduit - Bulk Delivery				
1840-4	Underground Conduit - Primary	$25,767			
1840-5	Underground Conduit - Secondary	$4,547			
1845	Underground Conductors and Devices				
1845-3	Underground Conductors and Devices - Bulk Delivery				
1845-4	Underground Conductors and Devices - Primary	$239,293			
1845-5	Underground Conductors and Devices - Secondary	$42,228			
1850	Line Transformers	$424,245			
1855	Services	$84,277			
1860	Meters	$110,781			
	Total	**$2,185,842**	**$0**	**$0**	**$0**
	SUB TOTAL from I3				
		5705	5710	5715	5720

2006 COST ALLOC
HALDIMAND C
EB-2009-0265
Friday, August 2
Sheet I4 Break

Ontario

Instructions:
This is an input sheet for the Break Out
***Please see Handbook for detailed instr**

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS			
		5705	5710	5715	5720
Account	Description	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
General Plant		Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1905	Land				
1906	Land Rights			$17,775	
1908	Buildings and Fixtures	$48,015			
1910	Leasehold Improvements				
1915	Office Furniture and Equipment	$30,760			
1920	Computer Equipment - Hardware	$50,799			
1925	Computer Software	$388,778			
1930	Transportation Equipment	$177,371			
1935	Stores Equipment				
1940	Tools, Shop and Garage Equipment	$29,086			
1945	Measurement and Testing Equipment				
1950	Power Operated Equipment				
1955	Communication Equipment	$0			
1960	Miscellaneous Equipment				
1970	Load Management Controls - Customer Premises				
1975	Load Management Controls - Utility Premises				
1980	System Supervisory Equipment				
1990	Other Tangible Property				
2005	Property Under Capital Leases				
2010	Electric Plant Purchased or Sold				
	Total	$724,809	$0	$17,775	$0
	SUB TOTAL from I3 I3 Directly Allocated				
	Grand Total	$2,910,651	$0	$17,775	$0

2006 COST ALLOC
HALDIMAND C
EB-2009-0265
Friday, August 2
Sheet I4 Break

Ontario

Instructions:
This is an input sheet for the Break Out
Please see Handbook for detailed instr

Enter Net Fixed Assets from "Return on Capital" Sheet (Revenue Req't Model)

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS				
		5705	5710	5715	5720	
Account	Description	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments	
To be Prorated						
1995	Contributed Capital - 1995					
2105	Accumulated Depreciation - 2105					
2120	Accumulated Depreciation - 2120					
	Total					
	Net Assets					
Amortization Expenses						
5705	Amortization Expense - Property, Plant, and Equipment	($2,910,651)	**Balanced**			
5710	Amortization of Limited Term Electric Plant		$0	**Balanced**		
5715	Amortization of Intangibles and Other Electric Plant			($17,775)	**Balanced**	
5720	Amortization of Electric Plant Acquisition Adjustments				$0	**Balanced**
	Total Amortization Expense					

HALDIMAND COUNTY HYDRO INC.

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Sheet I5 Miscellaneous Data Worksheet - First Run 2010 Cost of Service Rate Application

kMs of Roads in Service Area Where Distribution Lines Exist	1653
Deemed Equity Component of Rate Base (%)	40%

1	2	3	7	8	9	10
Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One
11.01	18.07	33.65	1.51	1.71	9.03	

Instructions (Cont'd):

Step 3: **Insert Approved Base Monthly Service Charge (Please refer to 2009 Tariff of Rates and Charges - Modified for Harmonization of Residential Classes)**

Step 4: **Insert Smart Meter Adder Included in Approved Monthly Service Charge**

2010 COST ALLOCATION STUDY

HALDIMAND COUNTY HYDRO INC.

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Sheet I6 Customer Data Worksheet - First Run 2010 Cost of Service Rate Application

Total kWhs	426,290,496

Total kWs	581,145

Total Approved Distribution Revenue ($)	$12,823,643

			1	2	3	7	8	9	10
	ID	**Total**	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**	**Embedded Distributor - Hydro One**
Billing Data									
kWh from Load Forecast for 2010 Rate Application	**CEN**	426,290,496	169,492,357	60,923,412	109,459,903	2,328,757	418,928	482,264	83,184,875
kW from Load Forecast for 2010 Rate Application	**CDEM**	581,145			296,554	6,475	1,167		276,949
kW, included in CDEM, from customers with line transformer allowance (calculated based on $ in 2010 Budget)		-							
Optional - 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**	343,105,621	169,492,357	60,923,412	109,459,903	2,328,757	418,928	482,264	
kWh - 30 year weather normalized amount		426,290,496	169,492,357	60,923,412	109,459,903	2,328,757	418,928	482,264	83,184,875
Distribution Revenue Calculated Based on Est. 2010 Rates(11.5% increase)	**CREV**	$12,823,643	$8,692,594	$2,112,502	$1,887,983	$88,080	$19,662	$22,822	$0
Bad Debt 7 Year Historical Average (2002 to 2008)	**BDHA**	$41,420	$31,979	$7,945	$1,496	$0	$0	$0	$0
Average (2002 to 2008)	**LPHA**	$59,198	44,777	8,467	5,619	221	-	114	-
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	1.0	1.0	1.0

Number of Bills (customer # * 12 mos.)	**CNB**	260,592	222,408	28,284	1,716	48	7,068	972	96
Number of Connections (Unmetered)	**CCON**	2,283				1,610	589	84	
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	**CCA**	21,708	18,534	2,357	143	4	589	81	
Bulk Customer Base	**CCB**	-							
Primary Customer Base	**CCP**	21,708	18,534	2,357	143	4	589	81	
Line Transformer Customer Base	**CCLT**	21,678	18,534	2,357	113	4	589	81	
Secondary Customer Base	**CCS**	20,154	17,589	1,864	27	4	589	81	
Weighted - Services	**CWCS**	23,870	17,589	3,728	270	1,610	589	84	-
Weighted Meter -Capital	**CWMC**	2,735,315	1,646,110	689,155	350,050	-	-	-	50,000
Weighted Meter Reading	**CWMR**	45,397	36,811	4,836	3,302	-	-	-	448
Weighted Bills	**CWNB**	299,172	222,408	56,568	12,012	48	7,068	972	96
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		12,823,643	8,692,594	2,112,502	1,887,983	88,080	19,662	22,822	-

Weather Normalized Data from Hydro

	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One
kWh - 30 year weather normalized amount	426,290,496	**169,492,357**	60,923,412	109,459,903	2,328,757	418,928	482,264	83,184,875
2010 Rate Application Distribution Loss Factor		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**

Bad Debt Data - 2002 to 2008

Year - 2002	38,512	27,028	11,484					
Year - 2003	(16,781)	(224)	(16,557)					
Year - 2004	24,061	19,525	4,536					
Year - 2005	39,132	23,121	16,011					
Year - 2006	291	258	33					
Year - 2007	158,133	121,642	36,241	250				
Year - 2008	46,590	32,501	3,869	10,220				
Seven-year average	**41,420**	**31,979**	**7,945**	**1,496**	**-**	**-**	**-**	**-**

Late Payment Data - 2002 to 2008

Year - 2002	88,600	69,668	11,369	7,551	(47)		59	
Year - 2003	47,128	33,978	6,615	6,364	135		36	
Year - 2004	58,216	41,424	8,664	7,424	113		590	
Year - 2005	61,934	46,702	9,127	6,075	7		22	
Year - 2006	47,829	34,936	7,314	4,846	715		17	
Year - 2007	58,356	46,043	8,312	3,610	364		27	
Year - 2008	52,321	40,686	7,868	3,464	259		45	
Seven-year average	**59,198**	**44,777**	**8,467**	**5,619**	**221**	**-**	**114**	**-**

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Sheet I7.1 Meter Capital Worksheet - First Run 2010 Cost of Service Rate Application

		Residential			General Service less than 50 kW			General Service 50 to 4,999 kW			
		1	2	3	1	2	3	1	2	3	1
		Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters
	Allocation Percentage Weighted Factor			60.18%			25%			13%	
	Cost Relative to Residential Average Cost			1.00			3.29			27.56	
	Total	18534	1646110	88.81569008	2357	689155	292.3865083	143	350050	2447.902098	0
Meter Types	**Cost per Meter (Installed)**										
Single Phase 200 Amp - Urban	50	12,474	623700		565	28250			0		
Single Phase 200 Amp - Rural	150	4,912	736800		877	131550			0		
Central Meter	250	884	221000		420	105000		7	1750		
Network Meter (Costs to be updated)	225	214	48150		23	5175			0		
Three-phase - No demand	210	46	9660		218	45780			0		
Smart Meters	300		0			0			0		
Demand without IT (usually three-phase)	500	1	500		100	50000		1	500		
Demand with IT	2,100	3	6300		154	323400		83	174300		
Demand with IT and Interval Capability - Secondary	2,300		0			0		45	103500		
Demand with IT and Interval Capability - Primary	10,000		0			0		7	70000		
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0		
LDC Specific 1			0			0			0		
LDC Specific 2			0			0			0		
LDC Specific 3			0			0			0		

Street Lighting		Sentinel Lighting			Unmetered Scattered Load			Embedded Distributor - Hydro One			TOTAL		
2	3	1	2	3	1	2	3	1	2	3	1	2	3
Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)
	0%			0%			0%			2%			100%
	-			-			-			112.59			1.46
0	-	0	0	-	0	0	-	5	50000	10000	21039	2735315	130.011645
0			0			0			0		13,039	651950	
0			0			0			0		5,789	868350	
0			0			0			0		1,311	327750	
0			0			0			0		237	53325	
0			0			0			0		264	55440	
0			0			0			0		0	0	
0			0			0			0		102	51000	
0			0			0			0		240	504000	
0			0			0			0		45	103500	
0			0			0		5	50000		12	120000	
0			0			0			0		0	0	
0			0			0			0		0	0	
0			0			0			0		0	0	
0			0			0			0		0	0	

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Sheet I7.2 Meter Reading Worksheet - First Run 2010 Cost of Service Rate Application

Weighting Factors based on Contractor Pricing

Description			1			2			3			
			Residential			General Service less than 50 kW			General Service 50 to 4,999 kW			
			Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units
	Allocation Percentage Weighted Factor				81.09%			10.65%			7.27%	
	Cost Relative to Residential Average Cost				1.00			1.03			11.63	
	Total		18,534	36,811	1.99	2,357	4,836	2.05	143	3,302	23.09	-
	Factor											
Residential - Urban - Outside		1.00	11,837	11,837			0			0		
Residential - Urban - Outside with other services		1.00		0			0			0		
Residential - Urban - Inside		2.00	736	1,472			0			0		
Residential - Urban - Inside - with other services		1.00		0			0			0		
Residential - Rural - Outside		3.00		0			0			0		
Residential - Rural - Outside with other services		2.00		0			0			0		
Rural/Residential Driving		4.00	5,790	23,160			0			0		
Semi Urban		2.00	171	342			0			0		
GS - Walking		2.00		0		2,296	4,592		91	182		
GS - Walking - with other services		3.00		0			0			0		
GS - Vehicle with other services --- TOU Read		3.00		0			0			0		
GS - Vehicle with other services		3.00		0			0			0		
Rural General Service		4.00		0		61	244			0		
LDC Specific 4		0.00		0			0			0		
Interval		49.00		0			0			0		
Interval - Daily Reads		60.00		0			0		52	3,120		
Interval - Interrogations		56.00		0			0			0		

7		8			9			10					
Street Lighting		Sentinel Lighting			Unmetered Scattered Load			Embedded Distributor - Hydro One			TOTAL		
Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	0.00%			0.00%			0.00%			0.99%			100.00%
	0.00			0.00			0.00			28.20			41.85
-	**0**	-	-	**0**	-	-	**0**	**8**	**448**	**56.00**	**21,042**	**45,397**	**83**
0			0			0			0		11,837	11,837	
0			0			0			0		-	-	
0			0			0			0		736	1,472	
0			0			0			0		-	-	
0			0			0			0		-	-	
0			0			0			0		-	-	
0			0			0			0		5,790	23,160	
0			0			0			0		171	342	
0			0			0			0		2,387	4,774	
0			0			0			0		-	-	
0			0			0			0		-	-	
0			0			0			0		-	-	
0			0			0			0		61	244	
0			0			0			0		-	-	
0			0			0			0		-	-	
0			0			0			0		52	3,120	
0			0			0		8	448		8	448	

2010 COST ALLOCATION STUDY

HALDIMAND COUNTY HYDRO INC.

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Sheet I8 Demand Data Worksheet - First Run 2010 Cost of Service Rate 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 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Hydro One
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	-	-	-	-	-	-	-	-
Bulk Delivery CP	BCP1	-	-	-	-	-	-	-	-
Total Sytem CP	DCP1	62,685	35,439	12,953	14,236	-	-	57	-
4 CP									
Transformation CP	TCP4	-	-	-	-	-	-	-	-
Bulk Delivery CP	BCP4	-	-	-	-	-	-	-	-
Total Sytem CP	DCP4	237,424	139,098	43,176	53,656	1,080	196	218	-
12 CP									
Transformation CP	TCP12	-	-	-	-	-	-	-	-
Bulk Delivery CP	BCP12	-	-	-	-	-	-	-	-
Total Sytem CP	DCP12	634,470	360,026	110,507	158,340	4,182	756	659	-
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	72,432	37,105	15,208	19,413	542	106	58	-
Primary NCP	PNCP1	72,432	37,105	15,208	19,413	542	106	58	-
Line Transformer NCP	LTNCP1	68,359	37,105	15,208	15,340	542	106	58	-
Secondary NCP	SNCP1	51,612	35,213	12,027	3,665	542	106	58	-
4 NCP									
Classification NCP from Load Data Provider	DNCP4	273,515	142,103	56,353	72,261	2,163	406	229	
Primary NCP	PNCP4	273,515	142,103	56,353	72,261	2,163	406	229	
Line Transformer NCP	LTNCP4	258,355	142,103	56,353	57,101	2,163	406	229	
Secondary NCP	SNCP4	195,865	134,858	44,566	13,644	2,163	406	229	
12 NCP									
Classification NCP from Load Data Provider	DNCP12	721,975	374,049	142,604	197,025	6,474	1,164	659	-
Primary NCP	PNCP12	721,975	374,049	142,604	197,025	6,474	1,164	659	-
Line Transformer NCP	LTNCP12	680,641	374,049	142,604	155,691	6,474	1,164	659	-
Secondary NCP	SNCP12	513,251	354,977	112,776	37,201	6,474	1,164	659	-

2010 COST ALLOCATION STUDY

HALDIMAND COUNTY HYDRO INC.

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Sheet I9 Direct Allocation Worksheet - First Run 2010 Cost of Service Rate Application

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 l Service less than	3 al Service 50 to 4,9	7 Street Lighting	8 Sentinel Lighting	9 hetered Scattered	10 ed Distributor - Hydro One
Instructions: To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line										
1995	Contributions and Grants - Credit	$0	Yes							
Instructions: The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications										
1805	Land	$0	Yes							
1806	Land Rights	$0	Yes							
1808	Buildings and Fixtures	$0	Yes							
1810	Leasehold Improvements	$0	Yes							
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes							
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes							
1825	Storage Battery Equipment	$0	Yes							
1830	Poles, Towers and Fixtures	$46,772	Yes							$46,772
1835	Overhead Conductors and Devices	$24,464	Yes							$24,464
1840	Underground Conduit	$0	Yes							
1845	Underground Conductors and Devices	$0	Yes							
1850	Line Transformers	$0	Yes							
1855	Services	$0	Yes							
1860	Meters	$0	Yes							
1905	Land	$0	Yes							
1906	Land Rights	$0	Yes							
1908	Buildings and Fixtures	$0	Yes							
1910	Leasehold Improvements	$0	Yes							
1915	Office Furniture and Equipment	$0	Yes							
1920	Computer Equipment - Hardware	$0	Yes							
1925	Computer Software	$0	Yes							
1930	Transportation Equipment	$0	Yes							
1935	Stores Equipment	$0	Yes							
1940	Tools, Shop and Garage Equipment	$0	Yes							
1945	Measurement and Testing Equipment	$0	Yes							
1950	Power Operated Equipment	$0	Yes							
1955	Communication Equipment	$0	Yes							
1960	Miscellaneous Equipment	$0	Yes							

1970	Load Management Controls - Customer Premises	$0	Yes							
1975	Load Management Controls - Utility Premises	$0	Yes							
1980	System Supervisory Equipment	$0	Yes							
1990	Other Tangible Property	$0	Yes							
2005	Property Under Capital Leases	$0	Yes							
2010	Electric Plant Purchased or Sold	$0	Yes							
2050	Completed Construction Not Classified--Electric	$0	Yes							
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($27,368)	Yes							($27,368)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes							
	Directly Allocated Net Fixed Assets			**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$43,868**
5005	Operation Supervision and Engineering	$679	Yes							$679
5010	Load Dispatching	$0	Yes							
5012	Station Buildings and Fixtures Expense	$0	Yes							
5014	Transformer Station Equipment - Operation Labour	$0	Yes							
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes							
5016	Distribution Station Equipment - Operation Labour	$0	Yes							
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes							
5020	Overhead Distribution Lines and Feeders - Operation Labour	$355	Yes							$355
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes							$0
5030	Overhead Subtransmission Feeders - Operation	$0	Yes							$0
5035	Overhead Distribution Transformers-Operation	$0	Yes							
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	Yes							
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	Yes							
5050	Underground Subtransmission Feeders - Operation	$0	Yes							
5055	Underground Distribution Transformers - Operation	$0	Yes							
5065	Meter Expense	$0	Yes							
5070	Customer Premises - Operation Labour	$0	Yes							
5075	Customer Premises - Materials and Expenses	$0	Yes							
5085	Miscellaneous Distribution Expense	$137,237	Yes							$137,237
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes							
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes							

5096	Other Rent	$0	Yes							
5105	Maintenance Supervision and Engineering	$177	Yes							$177
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes							
5112	Maintenance of Transformer Station Equipment	$0	Yes							
5114	Maintenance of Distribution Station Equipment	$0	Yes							
5120	Maintenance of Poles, Towers and Fixtures	$1,797	Yes							$1,797
5125	Maintenance of Overhead Conductors and Devices	$2,666	Yes							$2,666
5130	Maintenance of Overhead Services	$0	Yes							
5135	Overhead Distribution Lines and Feeders - Right of Way	$1,647	Yes							$1,647
5145	Maintenance of Underground Conduit	$0	Yes							
5150	Maintenance of Underground Conductors and Devices	$0	Yes							
5155	Maintenance of Underground Services	$0	Yes							
5160	Maintenance of Line Transformers	$0	Yes							
5175	Maintenance of Meters	$0	Yes							
5305	Supervision	$0	Yes							
5310	Meter Reading Expense	$0	Yes							
5315	Customer Billing	$0	Yes							
5320	Collecting	$0	Yes							
5325	Collecting- Cash Over and Short	$0	Yes							
5330	Collection Charges	$0	Yes							
5335	Bad Debt Expense	$0	Yes							
5340	Miscellaneous Customer Accounts Expenses	$0	Yes							
5405	Supervision	$0	Yes							
5410	Community Relations - Sundry	$0	Yes							
5415	Energy Conservation	$0	Yes							
5420	Community Safety Program	$0	Yes							
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes							
5505	Supervision	$0	Yes							
5510	Demonstrating and Selling Expense	$0	Yes							
5515	Advertising Expense	$0	Yes							
5520	Miscellaneous Sales Expense	$0	Yes							
5605	Executive Salaries and Expenses	$0	Yes							
5610	Management Salaries and Expenses	$901	Yes							$901
5615	General Administrative Salaries and Expenses	$790	Yes							$790
5620	Office Supplies and Expenses	$166	Yes							$166
5625	Administrative Expense Transferred Credit	$0	Yes							
5630	Outside Services Employed	$582	Yes							$582
5635	Property Insurance	$28	Yes							$28
5640	Injuries and Damages	$0	Yes							
5645	Employee Pensions and Benefits	$0	Yes							
5650	Franchise Requirements	$0	Yes							
5655	Regulatory Expenses	$139	Yes							$139
5660	General Advertising Expenses	$0	Yes							
5665	Miscellaneous General Expenses	$83	Yes							$83
5670	Rent	$0	Yes							

5675	Maintenance of General Plant	$0	Yes							
5680	Electrical Safety Authority Fees	$0	Yes							
5705	Amortization Expense - Property, Plant, and Equipment	$3,661	Yes							$3,661
5710	Amortization of Limited Term Electric Plant	$0	Yes							
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes							
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes							
6105	Taxes Other Than Income Taxes	$83	Yes							$83
6205	Donations	$0	Yes							
6210	Life Insurance	$0	Yes							
6215	Penalties	$0	Yes							
6225	Other Deductions	$0	Yes							
	Total Expenses			$0	$0	$0	$0	$0	$0	$150,989
	Depreciation Expense			$0	$0	$0	$0	$0	$0	$3,661

Total Net Fixed Assets Excluding Gen Plant	**$29,935,834**	**Allocated**	**Residential**	**l Service less than**	**al Service 50 to 4,9**	**Street Lighting**	**Sentinel Lighting**	**etered Scattered**	**ed Distributor - Hydro One**
Approved Total PILs	**$741,703**	**$1,087**	$0	$0	$0	$0	$0	$0	$1,087
Approved Total Return on Debt	**$1,275,060**	**$1,868**	$0	$0	$0	$0	$0	$0	$1,868
Approved Total Return on Equity	**$1,284,710**	**$1,883**	$0	$0	$0	$0	$0	$0	$1,883
		Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$155,827**

2010 COST ALLOCATION STUDY
HALDIMAND COUNTY HYDRO INC.
EB-2009-0265
Friday, August 28, 2009

Sheet O1 Revenue to Cost Summary Worksheet - First Run 2010 Cost of Service Rate Application

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Hydro One
crev	Distribution Revenue (sale)	$12,823,643	$8,692,594	$2,112,502	$1,887,983	$88,080	$19,662	$22,822	$0
mi	Miscellaneous Revenue (mi)	$1,115,334	$801,943	$182,535	$93,756	$18,901	$14,862	$2,757	$580
	Total Revenue	$13,938,977	$9,494,537	$2,295,037	$1,981,739	$106,981	$34,524	$25,579	$580
		$0							
	Expenses								
di	Distribution Costs (di)	$3,777,765	$2,535,334	$582,955	$434,463	$158,245	$57,892	$8,875	$0
cu	Customer Related Costs (cu)	$1,721,482	$1,259,560	$317,548	$105,221	$1,226	$25,472	$3,505	$8,950
ad	General and Administration (ad)	$2,058,842	$1,419,477	$336,718	$203,010	$60,516	$31,177	$4,635	$3,308
dep	Depreciation and Amortization (dep)	$2,928,426	$1,969,098	$460,365	$328,762	$117,751	$43,078	$6,593	$2,778
INPUT	PILs (INPUT)	$740,616	$497,869	$117,075	$82,690	$29,679	$10,858	$1,661	$783
INT	Interest	$1,273,192	$855,886	$201,263	$142,153	$51,022	$18,666	$2,855	$1,347
	Total Expenses	$12,500,323	$8,537,226	$2,015,924	$1,296,299	$418,440	$187,143	$28,125	$17,167
	Direct Allocation	$155,827	$0	$0	$0	$0	$0	$0	$155,827
NI	Allocated Net Income (NI)	$1,282,827	$862,364	$202,786	$143,229	$51,408	$18,807	$2,877	$1,357
	Revenue Requirement (includes NI)	$13,938,977	$9,399,590	$2,218,710	$1,439,527	$469,848	$205,950	$31,002	$174,351
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$50,557,944	$33,983,621	$7,978,555	$5,662,161	$2,027,046	$741,572	$113,480	$51,508
gp	General Plant - Gross	$8,669,510	$5,836,466	$1,368,327	$957,717	$350,418	$128,196	$19,591	$8,795
accum dep	Accumulated Depreciation	($21,841,750)	($14,651,377)	($3,446,218)	($2,489,895)	($866,349)	($316,944)	($48,589)	($22,376)
co	Capital Contribution	($2,790,019)	($1,907,646)	($433,010)	($272,849)	($123,121)	($45,042)	($6,814)	($1,537)
	Total Net Plant	$34,595,685	$23,261,063	$5,467,654	$3,857,134	$1,387,994	$507,782	$77,668	$36,390
	Directly Allocated Net Fixed Assets	$43,868	$0	$0	$0	$0	$0	$0	$43,868
COP	Cost of Power (COP)	$28,677,930	$13,807,045	$4,962,892	$8,916,731	$189,703	$34,126	$39,286	$728,147
	OM&A Expenses	$7,558,089	$5,214,372	$1,237,221	$742,693	$219,988	$114,541	$17,015	$12,258
	Directly Allocated Expenses	$147,328	$0	$0	$0	$0	$0	$0	$147,328
	Subtotal	***$36,383,347***	***$19,021,416***	***$6,200,113***	***$9,659,424***	***$409,691***	***$148,668***	***$56,301***	***$887,734***
	Working Capital	$5,457,502	$2,853,212	$930,017	$1,448,914	$61,454	$22,300	$8,445	$133,160
	Total Rate Base	$40,097,055	$26,114,276	$6,397,671	$5,306,048	$1,449,447	$530,082	$86,113	$213,418
		Rate Base Input equals Output							
	Equity Component of Rate Base	$16,038,822	$10,445,710	$2,559,069	$2,122,419	$579,779	$212,033	$34,445	$85,367
	Net Income on Allocated Assets	$1,282,827	$957,311	$279,113	$685,440	($311,459)	($152,619)	($2,545)	($172,414)
	Net Income on Direct Allocation Assets	$1,883	$0	$0	$0	$0	$0	$0	$1,883
	Net Income	$1,284,709	$957,311	$279,113	$685,440	($311,459)	($152,619)	($2,545)	($170,531)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	101.01%	103.44%	137.67%	22.77%	16.76%	82.51%	0.33%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	$94,947	$76,327	$542,211	($362,867)	($171,426)	($5,422)	($173,771)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.01%	9.16%	10.91%	32.30%	-53.72%	-71.98%	-7.39%	-199.76%

2010 COST ALLOCATION STUDY
HALDIMAND COUNTY HYDRO INC.
EB-2009-0265
Friday, August 28, 2009

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run 2010 Cost of Service Rate Application

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Hydro One
Customer Unit Cost per month - Avoided Cost	$4.06	$9.55	$55.50	$0.00	$2.44	$1.75	$144.77
Customer Unit Cost per month - Directly Related	$6.07	$13.77	$81.60	$0.02	$3.54	$2.81	$191.54
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$28.02	$37.41	$105.91	$24.25	$27.95	$24.58	$191.77
Fixed Charge per approved 2009 Tariff of Rates & Charges	$11.01	$18.07	$33.65	$1.51	$1.71	$9.03	$0.00

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Hydro One
General Plant - Gross Assets	$8,669,510	$5,836,466	$1,368,327	$957,717	$350,418	$128,196	$19,591	$8,795
General Plant - Accumulated Depreciation	($4,009,659)	($2,699,373)	($632,853)	($442,945)	($162,069)	($59,291)	($9,061)	($4,068)
General Plant - Net Fixed Assets	$4,659,851	$3,137,093	$735,474	$514,772	$188,349	$68,905	$10,530	$4,727
General Plant - Depreciation	$742,584	$499,921	$117,204	$82,033	$30,015	$10,981	$1,678	$753
Total Net Fixed Assets Excluding General Plant	$29,935,834	$20,123,970	$4,732,180	$3,342,363	$1,199,644	$438,876	$67,138	$31,663
Total Administration and General Expense	$2,058,842	$1,419,477	$336,718	$203,010	$60,516	$31,177	$4,635	$3,308
Total O&M	$5,499,247	$3,794,894	$900,503	$539,683	$159,472	$83,365	$12,380	$8,950

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Hydro One	
	Distribution Plant									
1860	Meters	$2,817,829	$1,695,767	$709,944	$360,610	$0	$0	$0	$51,508	CWMC
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant - Meters only	($1,085,674)	($653,358)	($273,533)	($138,938)	$0	$0	$0	($19,846)	
	Meter Net Fixed Assets	**$1,732,155**	**$1,042,409**	**$436,412**	**$221,671**	**$0**	**$0**	**$0**	**$31,663**	
	Misc Revenue									
4082	Retail Services Revenues	($34,956)	($25,987)	($6,610)	($1,404)	($6)	($826)	($114)	($11)	CWNB
4084	Service Transaction Requests (STR) Revenues	($1,070)	($795)	($202)	($43)	($0)	($25)	($3)	($0)	CWNB
4090	Electric Services Incidental to Energy Sales	($107,127)	($79,639)	($20,256)	($4,301)	($17)	($2,531)	($348)	($34)	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	NFA

4225	Late Payment Charges	($319,125)	($241,384)	($45,644)	($30,292)	($1,191)	$0	($614)	$0	LPHA
	Sub-total	*($462,278)*	*($347,806)*	*($72,712)*	*($36,039)*	*($1,214)*	*($3,382)*	*($1,079)*	*($46)*	
	Operation									
5065	Meter Expense	$276,493	$166,393	$69,662	$35,384	$0	$0	$0	$5,054	CWMC
5070	Customer Premises - Operation Labour	$15,294	$12,157	$1,546	$94	$1,056	$386	$55	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$291,787*	*$178,550*	*$71,208*	*$35,478*	*$1,056*	*$386*	*$55*	*$5,054*	
	Maintenance									
5175	Maintenance of Meters	$26,272	$15,810	$6,619	$3,362	$0	$0	$0	$480	1860
	Billing and Collection									
5310	Meter Reading Expense	$311,589	$252,658	$33,193	$22,664	$0	$0	$0	$3,075	CWMR
5315	Customer Billing	$602,980	$448,262	$114,013	$24,210	$97	$14,246	$1,959	$193	CWNB
5320	Collecting	$254,886	$189,485	$48,194	$10,234	$41	$6,022	$828	$82	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	$1,169,455	$890,405	$195,400	$57,108	$138	$20,267	$2,787	$3,350	
	Total Operation, Maintenance and Billing	$1,487,514	$1,084,766	$273,226	$95,948	$1,194	$20,654	$2,842	$8,885	
	Amortization Expense - Meters	$110,781	$66,668	$27,911	$14,177	$0	$0	$0	$2,025	
	Allocated PILs	$37,090	$22,311	$9,345	$4,752	$0	$0	$0	$682	
	Allocated Debt Return	$63,761	$38,355	$16,064	$8,170	$0	$0	$0	$1,172	
	Allocated Equity Return	$64,243	$38,646	$16,186	$8,231	$0	$0	$0	$1,181	
	Total	**$1,301,111**	**$902,940**	**$270,020**	**$95,239**	**($21)**	**$17,272**	**$1,764**	**$13,897**	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	7	8	9	10	
USoA Account #	**Accounts**	**Total**	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**	**Embedded Distributor - Hydro One**	
	Distribution Plant									
1860	Meters	$2,817,829	$1,695,767	$709,944	$360,610	$0	$0	$0	$51,508	CWMC
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant - Meters only	($1,085,674)	($653,358)	($273,533)	($138,938)	$0	$0	$0	($19,846)	
	Meter Net Fixed Assets	$1,732,155	$1,042,409	$436,412	$221,671	$0	$0	$0	$31,663	
	Allocated General Plant Net Fixed Assets	$269,194	$162,499	$67,827	$34,141	$0	$0	$0	$4,727	
	Meter Net Fixed Assets Including General Plant	$2,001,349	$1,204,909	$504,238	$255,812	$0	$0	$0	$36,390	
	Misc Revenue									
4082	Retail Services Revenues	($34,956)	($25,987)	($6,610)	($1,404)	($6)	($826)	($114)	($11)	CWNB
4084	Service Transaction Requests (STR) Revenues	($1,070)	($795)	($202)	($43)	($0)	($25)	($3)	($0)	CWNB
4090	Electric Services Incidental to Energy Sales	($107,127)	($79,639)	($20,256)	($4,301)	($17)	($2,531)	($348)	($34)	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($319,125)	($241,384)	($45,644)	($30,292)	($1,191)	$0	($614)	$0	LPHA
	Sub-total	*($462,278)*	*($347,806)*	*($72,712)*	*($36,039)*	*($1,214)*	*($3,382)*	*($1,079)*	*($46)*	
	Operation									
5065	Meter Expense	$276,493	$166,393	$69,662	$35,384	$0	$0	$0	$5,054	CWMC
5070	Customer Premises - Operation Labour	$15,294	$12,157	$1,546	$94	$1,056	$386	$55	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$291,787*	*$178,550*	*$71,208*	*$35,478*	*$1,056*	*$386*	*$55*	*$5,054*	
	Maintenance									

5175	Maintenance of Meters	$26,272	$15,810	$6,619	$3,362	$0	$0	$0	$480	1860
	Billing and Collection									
5310	Meter Reading Expense	$311,589	$252,658	$33,193	$22,664	$0	$0	$0	$3,075	CWMR
5315	Customer Billing	$602,980	$448,262	$114,013	$24,210	$97	$14,246	$1,959	$193	CWNB
5320	Collecting	$254,886	$189,485	$48,194	$10,234	$41	$6,022	$828	$82	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$1,169,455*	*$890,405*	*$195,400*	*$57,108*	*$138*	*$20,267*	*$2,787*	*$3,350*	
	Total Operation, Maintenance and Billing	$1,487,514	$1,084,766	$273,226	$95,948	$1,194	$20,654	$2,842	$8,885	
	Amortization Expense - Meters	$110,781	$66,668	$27,911	$14,177	$0	$0	$0	$2,025	
	Amortization Expense - General Plant assigned to Meters	*$42,898*	*$25,896*	*$10,809*	*$5,441*	*$0*	*$0*	*$0*	*$753*	
	Admin and General	$556,539	$405,756	$102,166	$36,092	$453	$7,724	$1,064	$3,284	
	Allocated PILs	$42,854	$25,789	$10,797	$5,484	$0	$0	$0	$783	
	Allocated Debt Return	$73,670	$44,334	$18,561	$9,428	$0	$0	$0	$1,347	
	Allocated Equity Return	$74,227	$44,670	$18,701	$9,499	$0	$0	$0	$1,357	
	Total	**$1,926,205**	**$1,350,073**	**$389,459**	**$140,029**	**$432**	**$24,996**	**$2,828**	**$18,388**	

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	7	8	9	10	
USoA Account #	**Accounts**	**Total**	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**	**Embedded Distributor - Hydro One**	
	Distribution Plant									
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$9,641,289	$7,663,578	$974,590	$59,129	$665,715	$243,544	$34,733	$0	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$615,401	$497,372	$52,709	$763	$45,527	$16,655	$2,375	$0	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$4,982,514	$3,960,455	$503,658	$30,557	$344,034	$125,861	$17,950	$0	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$615,816	$497,707	$52,745	$764	$45,557	$16,667	$2,377	$0	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$403,274	$320,551	$40,765	$2,473	$27,845	$10,187	$1,453	$0	PNCP
1840-5	Underground Conduit - Secondary	$71,166	$57,517	$6,095	$88	$5,265	$1,926	$275	$0	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	#N/A
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$3,473,986	$2,761,370	$351,168	$21,305	$239,873	$87,755	$12,515	$0	PNCP
1845-5	Underground Conductors and Devices - Secondary	$613,056	$495,476	$52,508	$761	$45,353	$16,592	$2,366	$0	SNCP
1850	Line Transformers	$6,419,999	$5,109,643	$649,802	$31,153	$443,861	$162,382	$23,158	$0	LTNCP
1855	Services	$2,431,707	$1,791,843	$379,782	$27,506	$164,015	$60,003	$8,557	$0	CWCS
1860	Meters	$2,817,829	$1,695,767	$709,944	$360,610	$0	$0	$0	$51,508	CWMC
	Sub-total	*$32,086,039*	*$24,851,278*	*$3,773,767*	*$535,109*	*$2,027,046*	*$741,572*	*$105,759*	*$51,508*	
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($13,028,832)	($10,106,681)	($1,519,209)	($209,830)	($827,402)	($302,695)	($43,169)	($19,846)	
	Customer Related Net Fixed Assets	$19,057,207	$14,744,597	$2,254,557	$325,279	$1,199,644	$438,876	$62,590	$31,663	
	Allocated General Plant Net Fixed Assets	$2,970,810	$2,298,511	$350,403	$50,098	$188,349	$68,905	$9,817	$4,727	
	Customer Related NFA Including General Plant	$22,028,017	$17,043,108	$2,604,960	$375,377	$1,387,994	$507,782	$72,407	$36,390	

	Misc Revenue									
4082	Retail Services Revenues	($34,956)	($25,987)	($6,610)	($1,404)	($6)	($826)	($114)	($11)	CWNB
4084	Service Transaction Requests (STR) Revenues	($1,070)	($795)	($202)	($43)	($0)	($25)	($3)	($0)	CWNB
4090	Electric Services Incidental to Energy Sales	($107,127)	($79,639)	($20,256)	($4,301)	($17)	($2,531)	($348)	($34)	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($319,125)	($241,384)	($45,644)	($30,292)	($1,191)	$0	($614)	$0	LPHA
4235	Miscellaneous Service Revenues	($212,558)	($158,018)	($40,191)	($8,534)	($34)	($5,022)	($691)	($68)	CWNB
	Sub-total	*($674,836)*	*($505,824)*	*($112,903)*	*($44,574)*	*($1,248)*	*($8,404)*	*($1,769)*	*($114)*	
	Operating and Maintenance									
5005	Operation Supervision and Engineering	$299,142	$236,666	$31,314	$1,784	$20,718	$7,579	$1,081	$0	1815-1855
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$71,790	$57,138	$7,171	$413	$4,984	$1,824	$260	$0	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$133,177	$105,995	$13,480	$646	$9,207	$3,368	$480	$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$35,165	$28,022	$3,473	$190	$2,454	$898	$128	$0	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5055	Underground Distribution Transformers - Operation	$9,418	$7,495	$953	$46	$651	$238	$34	$0	1850
5065	Meter Expense	$276,493	$166,393	$69,662	$35,384	$0	$0	$0	$5,054	CWMC
5070	Customer Premises - Operation Labour	$15,294	$12,157	$1,546	$94	$1,056	$386	$55	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	CCA
5085	Miscellaneous Distribution Expense	$33,388	$26,415	$3,495	$199	$2,312	$846	$121	$0	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$78,907	$62,428	$8,260	$470	$5,465	$1,999	$285	$0	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$363,361	$289,115	$36,394	$2,122	$25,197	$9,218	$1,315	$0	1830
5125	Maintenance of Overhead Conductors and Devices	$538,978	$429,209	$53,568	$3,015	$37,508	$13,722	$1,957	$0	1835
5130	Maintenance of Overhead Services	$158,103	$116,501	$24,692	$1,788	$10,664	$3,901	$556	$0	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$332,923	$264,975	$33,254	$1,915	$23,115	$8,456	$1,206	$0	1830 & 1835
5145	Maintenance of Underground Conduit	$6,412	$5,110	$633	$35	$447	$164	$23	$0	1840
5150	Maintenance of Underground Conductors and Devices	$19,925	$15,878	$1,968	$108	$1,391	$509	$73	$0	1845
5155	Maintenance of Underground Services	$111,495	$82,157	$17,413	$1,261	$7,520	$2,751	$392	$0	1855
5160	Maintenance of Line Transformers	$95,622	$76,105	$9,678	$464	$6,611	$2,419	$345	$0	1850
5175	Maintenance of Meters	$26,272	$15,810	$6,619	$3,362	$0	$0	$0	$480	1860
	Sub-total	*$2,605,864*	*$1,997,568*	*$323,574*	*$53,296*	*$159,301*	*$58,279*	*$8,311*	*$5,534*	
	Billing and Collection									
5305	Supervision	$144,980	$107,780	$27,413	$5,821	$23	$3,425	$471	$47	CWNB
5310	Meter Reading Expense	$311,589	$252,658	$33,193	$22,664	$0	$0	$0	$3,075	CWMR
5315	Customer Billing	$602,980	$448,262	$114,013	$24,210	$97	$14,246	$1,959	$193	CWNB
5320	Collecting	$254,886	$189,485	$48,194	$10,234	$41	$6,022	$828	$82	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	CWNB
5335	Bad Debt Expense	$30,000	$23,162	$5,755	$1,083	$0	$0	$0	$0	BDHA
5340	Miscellaneous Customer Accounts Expenses	$58,988	$43,852	$11,154	$2,368	$9	$1,394	$192	$19	CWNB
	Sub-total	*$1,403,423*	*$1,065,200*	*$239,721*	*$66,381*	*$170*	*$25,086*	*$3,450*	*$3,416*	
	Sub Total Operating, Maintenance and Biling	*$4,009,287*	*$3,062,768*	*$563,295*	*$119,677*	*$159,472*	*$83,365*	*$11,761*	*$8,950*	
	Amortization Expense - Customer Related	$1,376,932	$1,069,609	$159,254	$21,634	$87,736	$32,097	$4,578	$2,025	
	Amortization Expense - General Plant assigned to Meters	$473,422	$366,286	$55,839	$7,983	$30,015	$10,981	$1,564	$753	
	Admin and General	$1,500,678	$1,145,626	$210,629	$45,018	$60,516	$31,177	$4,403	$3,308	
	Allocated PILs	$471,478	$364,783	$55,778	$8,047	$29,679	$10,858	$1,548	$783	

Allocated Debt Return	$810,516	$627,098	$95,888	$13,834	$51,022	$18,666	$2,662	$1,347
Allocated Equity Return	$816,650	$631,844	$96,614	$13,939	$51,408	$18,807	$2,682	$1,357
PLCC Adjustment for Line Transformer	$122,806	$107,936	$13,723	$658	$0	$0	$489	$0
PLCC Adjustment for Primary Costs	$405,319	$355,711	$45,245	$2,750	$0	$0	$1,613	$0
PLCC Adjustment for Secondary Costs	$74,612	$66,381	$7,261	$416	$0	$0	$555	$0
Total	$8,181,389	**$6,232,162**	**$1,058,165**	**$181,735**	**$468,600**	**$197,546**	**$24,772**	**$18,410**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One
Distribution Plant								
CWMC	$ 2,817,829	$ 1,695,767	$ 709,944	$ 360,610	$ -	$ -	$ -	$ 51,508
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (1,085,674)	$ (653,358)	$ (273,533)	$ (138,938)	$ -	$ -	$ -	$ (19,846)
Meter Net Fixed Assets	$ 1,732,155	$ 1,042,409	$ 436,412	$ 221,671	$ -	$ -	$ -	$ 31,663
Misc Revenue								
CWNB	$ (143,153)	$ (106,422)	$ (27,068)	$ (5,748)	$ (23)	$ (3,382)	$ (465)	$ (46)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (319,125)	$ (241,384)	$ (45,644)	$ (30,292)	$ (1,191)	$ -	$ (614)	$ -
Sub-total	$ (462,278)	$ (347,806)	$ (72,712)	$ (36,039)	$ (1,214)	$ (3,382)	$ (1,079)	$ (46)
Operation								
CWMC	$ 276,493	$ 166,393	$ 69,662	$ 35,384	$ -	$ -	$ -	$ 5,054
CCA	$ 15,294	$ 12,157	$ 1,546	$ 94	$ 1,056	$ 386	$ 55	$ -
Sub-total	$ 291,787	$ 178,550	$ 71,208	$ 35,478	$ 1,056	$ 386	$ 55	$ 5,054
Maintenance								
1860	$ 26,272	$ 15,810	$ 6,619	$ 3,362	$ -	$ -	$ -	$ 480
Billing and Collection								
CWMR	$ 311,589	$ 252,658	$ 33,193	$ 22,664	$ -	$ -	$ -	$ 3,075
CWNB	$ 857,866	$ 637,748	$ 162,207	$ 34,444	$ 138	$ 20,267	$ 2,787	$ 275
Sub-total	$ 1,169,455	$ 890,405	$ 195,400	$ 57,108	$ 138	$ 20,267	$ 2,787	$ 3,350
Total Operation, Maintenance and Billing	$ 1,487,514	$ 1,084,766	$ 273,226	$ 95,948	$ 1,194	$ 20,654	$ 2,842	$ 8,885
Amortization Expense - Meters	$ 110,781	$ 66,668	$ 27,911	$ 14,177	$ -	$ -	$ -	$ 2,025
Allocated PILs	$ 37,090	$ 22,311	$ 9,345	$ 4,752	$ -	$ -	$ -	$ 682
Allocated Debt Return	$ 63,761	$ 38,355	$ 16,064	$ 8,170	$ -	$ -	$ -	$ 1,172
Allocated Equity Return	$ 64,243	$ 38,646	$ 16,186	$ 8,231	$ -	$ -	$ -	$ 1,181
Total	**$ 1,301,111**	**$ 902,940**	**$ 270,020**	**$ 95,239**	**$ (21)**	**$ 17,272**	**$ 1,764**	**$ 13,897**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One

Distribution Plant								
CWMC	$ 2,817,829	$ 1,695,767	$ 709,944	$ 360,610	$ -	$ -	$ -	$ 51,508
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (1,085,674)	$ (653,358)	$ (273,533)	$ (138,938)	$ -	$ -	$ -	$ (19,846)
Meter Net Fixed Assets	$ 1,732,155	$ 1,042,409	$ 436,412	$ 221,671	$ -	$ -	$ -	$ 31,663
Allocated General Plant Net Fixed Assets	$ 269,194	$ 162,499	$ 67,827	$ 34,141	$ -	$ -	$ -	$ 4,727
Meter Net Fixed Assets Including General Plant	$ 2,001,349	$ 1,204,909	$ 504,238	$ 255,812	$ -	$ -	$ -	$ 36,390
Misc Revenue								
CWNB	$ (143,153)	$ (106,422)	$ (27,068)	$ (5,748)	$ (23)	$ (3,382)	$ (465)	$ (46)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (319,125)	$ (241,384)	$ (45,644)	$ (30,292)	$ (1,191)	$ -	$ (614)	$ -
Sub-total	*$ (462,278)*	*$ (347,806)*	*$ (72,712)*	*$ (36,039)*	*$ (1,214)*	*$ (3,382)*	*$ (1,079)*	*$ (46)*
Operation								
CWMC	$ 276,493	$ 166,393	$ 69,662	$ 35,384	$ -	$ -	$ -	$ 5,054
CCA	$ 15,294	$ 12,157	$ 1,546	$ 94	$ 1,056	$ 386	$ 55	$ -
Sub-total	*$ 291,787*	*$ 178,550*	*$ 71,208*	*$ 35,478*	*$ 1,056*	*$ 386*	*$ 55*	*$ 5,054*
Maintenance								
1860	$ 26,272	$ 15,810	$ 6,619	$ 3,362	$ -	$ -	$ -	$ 480
Billing and Collection								
CWMR	$ 311,589	$ 252,658	$ 33,193	$ 22,664	$ -	$ -	$ -	$ 3,075
CWNB	$ 857,866	$ 637,748	$ 162,207	$ 34,444	$ 138	$ 20,267	$ 2,787	$ 275
Sub-total	*$ 1,169,455*	*$ 890,405*	*$ 195,400*	*$ 57,108*	*$ 138*	*$ 20,267*	*$ 2,787*	*$ 3,350*
Total Operation, Maintenance and Billing	$ 1,487,514	$ 1,084,766	$ 273,226	$ 95,948	$ 1,194	$ 20,654	$ 2,842	$ 8,885
Amortization Expense - Meters	$ 110,781	$ 66,668	$ 27,911	$ 14,177	$ -	$ -	$ -	$ 2,025
Amortization Expense - General Plant assigned to Meters	$ 42,898	$ 25,896	$ 10,809	$ 5,441	$ -	$ -	$ -	$ 753
Admin and General	$ 556,539	$ 405,756	$ 102,166	$ 36,092	$ 453	$ 7,724	$ 1,064	$ 3,284
Allocated PILs	$ 42,854	$ 25,789	$ 10,797	$ 5,484	$ -	$ -	$ -	$ 783
Allocated Debt Return	$ 73,670	$ 44,334	$ 18,561	$ 9,428	$ -	$ -	$ -	$ 1,347
Allocated Equity Return	$ 74,227	$ 44,670	$ 18,701	$ 9,499	$ -	$ -	$ -	$ 1,357
Total	**$ 1,926,205**	**$ 1,350,073**	**$ 389,459**	**$ 140,029**	**$ 432**	**$ 24,996**	**$ 2,828**	**$ 18,388**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One
	Distribution Plant								
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 18,501,064	$ 14,705,953	$ 1,870,181	$ 113,465	$ 1,277,468	$ 467,347	$ 66,650	$ -
	SNCP	$ 1,915,440	$ 1,548,071	$ 164,057	$ 2,376	$ 141,702	$ 51,840	$ 7,393	$ -
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 6,419,999	$ 5,109,643	$ 649,802	$ 31,153	$ 443,861	$ 162,382	$ 23,158	$ -
	CWCS	$ 2,431,707	$ 1,791,843	$ 379,782	$ 27,506	$ 164,015	$ 60,003	$ 8,557	$ -
	CWMC	$ 2,817,829	$ 1,695,767	$ 709,944	$ 360,610	$ -	$ -	$ -	$ 51,508
	Sub-total	*$ 32,086,039*	*$ 24,851,278*	*$ 3,773,767*	*$ 535,109*	*$ 2,027,046*	*$ 741,572*	*$ 105,759*	*$ 51,508*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (13,028,832)	$ (10,106,681)	$ (1,519,209)	$ (209,830)	$ (827,402)	$ (302,695)	$ (43,169)	$ (19,846)
	Customer Related Net Fixed Assets	$ 19,057,207	$ 14,744,597	$ 2,254,557	$ 325,279	$ 1,199,644	$ 438,876	$ 62,590	$ 31,663
	Allocated General Plant Net Fixed Assets	$ 2,970,810	$ 2,298,511	$ 350,403	$ 50,098	$ 188,349	$ 68,905	$ 9,817	$ 4,727

Customer Related NFA Including General Plant	$ 22,028,017	$ 17,043,108	$ 2,604,960	$ 375,377	$ 1,387,994	$ 507,782	$ 72,407	$ 36,390
Misc Revenue								
CWNB	$ (355,711)	$ (264,440)	$ (67,258)	$ (14,282)	$ (57)	$ (8,404)	$ (1,156)	$ (114)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (319,125)	$ (241,384)	$ (45,644)	$ (30,292)	$ (1,191)	$ -	$ (614)	$ -
Sub-total	*$ (674,836)*	*$ (505,824)*	*$ (112,903)*	*$ (44,574)*	*$ (1,248)*	*$ (8,404)*	*$ (1,769)*	*$ (114)*
Operating and Maintenance								
1815-1855	$ 411,437	$ 325,508	$ 43,070	$ 2,453	$ 28,495	$ 10,425	$ 1,487	$ -
1830 & 1835	$ 404,713	$ 322,113	$ 40,425	$ 2,328	$ 28,100	$ 10,280	$ 1,466	$ -
1850	$ 238,216	$ 189,595	$ 24,111	$ 1,156	$ 16,470	$ 6,025	$ 859	$ -
1840 & 1845	$ 35,165	$ 28,022	$ 3,473	$ 190	$ 2,454	$ 898	$ 128	$ -
CWMC	$ 276,493	$ 166,393	$ 69,662	$ 35,384	$ -	$ -	$ -	$ 5,054
CCA	$ 15,294	$ 12,157	$ 1,546	$ 94	$ 1,056	$ 386	$ 55	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ 363,361	$ 289,115	$ 36,394	$ 2,122	$ 25,197	$ 9,218	$ 1,315	$ -
1835	$ 538,978	$ 429,209	$ 53,568	$ 3,015	$ 37,508	$ 13,722	$ 1,957	$ -
1855	$ 269,598	$ 198,658	$ 42,106	$ 3,049	$ 18,184	$ 6,652	$ 949	$ -
1840	$ 6,412	$ 5,110	$ 633	$ 35	$ 447	$ 164	$ 23	$ -
1845	$ 19,925	$ 15,878	$ 1,968	$ 108	$ 1,391	$ 509	$ 73	$ -
1860	$ 26,272	$ 15,810	$ 6,619	$ 3,362	$ -	$ -	$ -	$ 480
Sub-total	*$ 2,605,864*	*$ 1,997,568*	*$ 323,574*	*$ 53,296*	*$ 159,301*	*$ 58,279*	*$ 8,311*	*$ 5,534*
Billing and Collection								
CWNB	$ 1,061,834	$ 789,380	$ 200,774	$ 42,634	$ 170	$ 25,086	$ 3,450	$ 341
CWMR	$ 311,589	$ 252,658	$ 33,193	$ 22,664	$ -	$ -	$ -	$ 3,075
BDHA	$ 30,000	$ 23,162	$ 5,755	$ 1,083	$ -	$ -	$ -	$ -
Sub-total	*$ 1,403,423*	*$ 1,065,200*	*$ 239,721*	*$ 66,381*	*$ 170*	*$ 25,086*	*$ 3,450*	*$ 3,416*
Sub Total Operating, Maintenance and Biling	*$ 4,009,287*	*$ 3,062,768*	*$ 563,295*	*$ 119,677*	*$ 159,472*	*$ 83,365*	*$ 11,761*	*$ 8,950*
Amortization Expense - Customer Related	$ 1,376,932	$ 1,069,609	$ 159,254	$ 21,634	$ 87,736	$ 32,097	$ 4,578	$ 2,025
Amortization Expense - General Plant assigned to Meters	$ 473,422	$ 366,286	$ 55,839	$ 7,983	$ 30,015	$ 10,981	$ 1,564	$ 753
Admin and General	$ 1,500,678	$ 1,145,626	$ 210,629	$ 45,018	$ 60,516	$ 31,177	$ 4,403	$ 3,308
Allocated PILs	$ 471,478	$ 364,783	$ 55,778	$ 8,047	$ 29,679	$ 10,858	$ 1,548	$ 783
Allocated Debt Return	$ 810,516	$ 627,098	$ 95,888	$ 13,834	$ 51,022	$ 18,666	$ 2,662	$ 1,347
Allocated Equity Return	$ 816,650	$ 631,844	$ 96,614	$ 13,939	$ 51,408	$ 18,807	$ 2,682	$ 1,357
PLCC Adjustment for Line Transformer	$ 122,806	$ 107,936	$ 13,723	$ 658	$ -	$ -	$ 489	$ -
PLCC Adjustment for Primary Costs	$ 405,319	$ 355,711	$ 45,245	$ 2,750	$ -	$ -	$ 1,613	$ -
PLCC Adjustment for Secondary Costs	$ 74,612	$ 66,381	$ 7,261	$ 416	$ -	$ -	$ 555	$ -
Total	**$ 8,181,389**	**$ 6,232,162**	**$ 1,058,165**	**$ 181,735**	**$ 468,600**	**$ 197,546**	**$ 24,772**	**$ 18,410**

Sheet O3.5 USL Metering Credit Worksheet - First Run 2010 Cost of Service Rate Application

ALLOCATION BY RATE CLASSIFICATION

Description	General Service less than 50 kW
Depreciation on Acct 1860 Metering	$27,911
Depreciation on General Plant Assigned to Metering	$10,809
Acct 5065 - Meter expense	$69,662
Acct 5070 & 5075 - Customer Premises	$1,546
Acct 5175 - Meter Maintenance	$6,619
Acct 5310 - Meter Reading	$33,193
Admin and General Assigned to Metering	$41,513
PILs on Metering	$10,797
Debt Return on Metering	$18,561
Equity Return on Metering	$18,701
Total	$239,311
Number of Customers	2,357
Metering Unit Cost ($/Customer/Month)	**$8.46**
General Plant - Gross Assets	$1,368,327
General Plant - Accumulated Depreciation	($632,853)
General Plant - Net Fixed Assets	$735,474
General Plant - Depreciation	$117,204
Total Net Fixed Assets Excluding General Plant	$4,732,180
Total Administration and General Expense	$336,718
Total O&M	$900,503
Metering Rate Base	
Acct 1860 - Metering - Gross Assets	$709,944
Metering - Accumulated Depreciation	($273,533)
Metering - Net Fixed Assets	$436,412
General Plant Assigned to Metering - NFA	$67,827
Metering Net Fixed Assets Including General Plant	$504,238

ALLOCATION BY RATE CLASSIFICATION

				1	2	3	7	8	9	10
USoA Account #	Accounts	O1 Grouping	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One
1565	Conservation and Demand Management Expenditures and Recoveries	dp	$0	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	gp	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	dp	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	dp	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	dp	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	dp	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	dp	$580,903	$275,436	$128,796	$176,439	$0	$0	$232	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	dp	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	dp	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	dp	$16,068,816	$10,711,204	$2,399,682	$2,011,373	$665,715	$243,544	$37,297	$0
1830-5	Poles, Towers and Fixtures - Secondary	dp	$1,025,669	$767,640	$158,024	$35,208	$45,527	$16,655	$2,615	$0
1835	Overhead Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	dp	$8,304,190	$5,535,435	$1,240,130	$1,039,456	$344,034	$125,861	$19,275	$0
1835-5	Overhead Conductors and Devices - Secondary	dp	$1,026,361	$768,157	$158,131	$35,232	$45,557	$16,667	$2,617	$0
1840	Underground Conduit	dp	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	dp	$672,124	$448,027	$100,374	$84,131	$27,845	$10,187	$1,560	$0
1840-5	Underground Conduit - Secondary	dp	$118,610	$88,771	$18,274	$4,072	$5,265	$1,926	$302	$0
1845	Underground Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	dp	$5,789,976	$3,859,502	$864,663	$724,746	$239,873	$87,755	$13,439	$0
1845-5	Underground Conductors and Devices - Secondary	dp	$1,021,761	$764,714	$157,422	$35,074	$45,353	$16,592	$2,605	$0
1850	Line Transformers	dp	$10,699,998	$7,277,126	$1,663,333	$1,128,315	$443,861	$162,382	$24,981	$0
1855	Services	dp	$2,431,707	$1,791,843	$379,782	$27,506	$164,015	$60,003	$8,557	$0
1860	Meters	dp	$2,817,829	$1,695,767	$709,944	$360,610	$0	$0	$0	$51,508
1905	Land	gp	$139,071	$93,625	$21,950	$15,363	$5,621	$2,056	$314	$141
1906	Land Rights	gp	$695,389	$468,148	$109,755	$76,819	$28,107	$10,283	$1,571	$705
1908	Buildings and Fixtures	gp	$2,013,342	$1,355,417	$317,770	$222,413	$81,378	$29,771	$4,550	$2,042
1910	Leasehold Improvements	gp	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	gp	$348,916	$234,896	$55,070	$38,545	$14,103	$5,159	$788	$354

1920	Computer Equipment - Hardware	gp	$554,984	$373,625	$87,594	$61,309	$22,432	$8,207	$1,254	$563
1925	Computer Software	gp	$2,407,443	$1,620,733	$379,972	$265,949	$97,308	$35,599	$5,440	$2,442
1930	Transportation Equipment	gp	$1,908,883	$1,285,093	$301,283	$210,874	$77,156	$28,227	$4,314	$1,937
1935	Stores Equipment	gp	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	gp	$535,201	$360,307	$84,472	$59,123	$21,633	$7,914	$1,209	$543
1945	Measurement and Testing Equipment	gp	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	gp	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	gp	$66,281	$44,622	$10,461	$7,322	$2,679	$980	$150	$67
1960	Miscellaneous Equipment	gp	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	gp	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	gp	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	gp	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	gp	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	co	($2,790,019)	($1,907,646)	($433,010)	($272,849)	($123,121)	($45,042)	($6,814)	($1,537)
2005	Property Under Capital Leases	gp	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	gp	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	accum dep	($21,638,135)	($14,514,300)	($3,414,081)	($2,467,402)	($858,119)	($313,933)	($48,129)	($22,170)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	accum dep	($203,615)	($137,077)	($32,137)	($22,493)	($8,230)	($3,011)	($460)	($207)
3046	Balance Transferred From Income	NI	($1,282,827)	($862,364)	($202,786)	($143,229)	($51,408)	($18,807)	($2,877)	($1,357)
4080	Distribution Services Revenue	CREV	($12,823,643)	($8,692,594)	($2,112,502)	($1,887,983)	($88,080)	($19,662)	($22,822)	$0
4082	Retail Services Revenues	mi	($34,956)	($25,987)	($6,610)	($1,404)	($6)	($826)	($114)	($11)
4084	Service Transaction Requests (STR) Revenues	mi	($1,070)	($795)	($202)	($43)	($0)	($25)	($3)	($0)
4090	Electric Services Incidental to Energy Sales	mi	($107,127)	($79,639)	($20,256)	($4,301)	($17)	($2,531)	($348)	($34)
4205	Interdepartmental Rents	mi	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	mi	$0	$0	$0	$0	$0	$0	$0	$0
4215	Other Utility Operating Income	mi	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	mi	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	mi	($319,125)	($241,384)	($45,644)	($30,292)	($1,191)	$0	($614)	$0
4235	Miscellaneous Service Revenues	mi	($212,558)	($158,018)	($40,191)	($8,534)	($34)	($5,022)	($691)	($68)
4240	Provision for Rate Refunds	mi	$0	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	mi	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	mi	$0	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	mi	$0	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	mi	($10,400)	($6,991)	($1,644)	($1,161)	($417)	($152)	($23)	($11)
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	mi	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	mi	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	mi	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	mi	$0	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	mi	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	mi	($362,550)	($243,719)	($57,311)	($40,479)	($14,529)	($5,315)	($813)	($383)
4395	Rate-Payer Benefit Including Interest	mi	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	mi	$0	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	mi	($67,548)	($45,408)	($10,678)	($7,542)	($2,707)	($990)	($151)	($71)
4415	Equity in Earnings of Subsidiary Companies	mi	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	cop	$22,363,781	$11,047,589	$3,971,016	$7,134,646	$151,789	$27,306	$31,434	$0
4708	Charges-WMS	cop	$2,373,264	$1,172,380	$421,408	$757,135	$16,108	$2,898	$3,336	$0
4710	Cost of Power Adjustments	cop	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	cop	$209,412	$103,448	$37,184	$66,808	$1,421	$256	$294	$0
4714	Charges-NW	cop	$1,955,675	$777,573	$279,496	$502,165	$10,684	$1,922	$2,212	$381,624
4715	System Control and Load Dispatching	cop	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	cop	$1,775,798	$706,054	$253,789	$455,977	$9,701	$1,745	$2,009	$346,523

4730	Rural Rate Assistance Expense	cop	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	di	$498,570	$335,261	$76,710	$57,137	$20,718	$7,579	$1,164	$0
5010	Load Dispatching	di	$0	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	di	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	di	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	di	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	di	$17,889	$8,482	$3,966	$5,433	$0	$0	$7	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	di	$19,570	$9,279	$4,339	$5,944	$0	$0	$8	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	di	$119,650	$80,517	$17,912	$14,133	$4,984	$1,824	$280	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	di	$0	$0	$0	$0	$0	$0	$0	$0
5030	Overhead Subtransmission Feeders - Operation	di	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	di	$221,961	$150,957	$34,504	$23,406	$9,207	$3,368	$518	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	di	$58,608	$39,787	$8,794	$6,537	$2,454	$898	$138	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	di	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	di	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	di	$15,696	$10,675	$2,440	$1,655	$651	$238	$37	$0
5065	Meter Expense	cu	$276,493	$166,393	$69,662	$35,384	$0	$0	$0	$5,054
5070	Customer Premises - Operation Labour	cu	$15,294	$12,157	$1,546	$94	$1,056	$386	$55	$0
5075	Customer Premises - Materials and Expenses	cu	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	di	$55,646	$37,419	$8,562	$6,377	$2,312	$846	$130	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	di	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	di	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	di	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	di	$131,512	$88,435	$20,235	$15,071	$5,465	$1,999	$307	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	di	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	di	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	di	$107,029	$50,748	$23,730	$32,508	$0	$0	$43	$0
5120	Maintenance of Poles, Towers and Fixtures	di	$605,601	$406,657	$90,611	$72,504	$25,197	$9,218	$1,414	$0
5125	Maintenance of Overhead Conductors and Devices	di	$898,297	$606,877	$134,617	$103,465	$37,508	$13,722	$2,108	$0
5130	Maintenance of Overhead Services	di	$158,103	$116,501	$24,692	$1,788	$10,664	$3,901	$556	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	di	$554,871	$373,395	$83,067	$65,540	$23,115	$8,456	$1,298	$0
5145	Maintenance of Underground Conduit	di	$10,687	$7,255	$1,604	$1,192	$447	$164	$25	$0
5150	Maintenance of Underground Conductors and Devices	di	$33,209	$22,544	$4,983	$3,704	$1,391	$509	$78	$0
5155	Maintenance of Underground Services	di	$111,495	$82,157	$17,413	$1,261	$7,520	$2,751	$392	$0
5160	Maintenance of Line Transformers	di	$159,370	$108,388	$24,774	$16,806	$6,611	$2,419	$372	$0
5175	Maintenance of Meters	cu	$26,272	$15,810	$6,619	$3,362	$0	$0	$0	$480
5305	Supervision	cu	$144,980	$107,780	$27,413	$5,821	$23	$3,425	$471	$47
5310	Meter Reading Expense	cu	$311,589	$252,658	$33,193	$22,664	$0	$0	$0	$3,075
5315	Customer Billing	cu	$602,980	$448,262	$114,013	$24,210	$97	$14,246	$1,959	$193
5320	Collecting	cu	$254,886	$189,485	$48,194	$10,234	$41	$6,022	$828	$82
5325	Collecting- Cash Over and Short	cu	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	cu	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	cu	$30,000	$23,162	$5,755	$1,083	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	cu	$58,988	$43,852	$11,154	$2,368	$9	$1,394	$192	$19
5405	Supervision	ad	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	ad	$28,836	$19,899	$4,722	$2,830	$836	$437	$65	$47
5415	Energy Conservation	ad	$18,000	$12,421	$2,948	$1,766	$522	$273	$41	$29
5420	Community Safety Program	ad	$0	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	ad	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	ad	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	ad	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	ad	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	ad	$0	$0	$0	$0	$0	$0	$0	$0

5605	Executive Salaries and Expenses	ad	$71,428	$49,291	$11,696	$7,010	$2,071	$1,083	$161	$116
5610	Management Salaries and Expenses	ad	$653,463	$450,939	$107,005	$64,129	$18,950	$9,906	$1,471	$1,064
5615	General Administrative Salaries and Expenses	ad	$542,191	$374,153	$88,784	$53,209	$15,723	$8,219	$1,221	$882
5620	Office Supplies and Expenses	ad	$112,214	$77,436	$18,375	$11,012	$3,254	$1,701	$253	$183
5625	Administrative Expense Transferred Credit	ad	$0	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	ad	$401,524	$277,082	$65,750	$39,405	$11,644	$6,087	$904	$653
5635	Property Insurance	ad	$19,380	$13,047	$3,059	$2,141	$783	$287	$44	$20
5640	Injuries and Damages	ad	$0	$0	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefits	ad	$0	$0	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	ad	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	ad	$101,069	$69,746	$16,550	$9,919	$2,931	$1,532	$228	$164
5660	General Advertising Expenses	ad	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	ad	$57,372	$39,591	$9,395	$5,630	$1,664	$870	$129	$93
5670	Rent	ad	$0	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	ad	$0	$0	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fees	ad	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	cop	$0	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	dep	$2,910,651	$1,957,132	$457,560	$326,798	$117,032	$42,815	$6,553	$2,760
5710	Amortization of Limited Term Electric Plant	dep	$0	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	dep	$17,775	$11,966	$2,805	$1,964	$718	$263	$40	$18
5720	Amortization of Electric Plant Acquisition Adjustments	dep	$0	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	dep	$0	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	dep	$0	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	dep	$0	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	INT	$1,273,192	$855,886	$201,263	$142,153	$51,022	$18,666	$2,855	$1,347
6105	Taxes Other Than Income Taxes	ad	$53,364	$35,873	$8,436	$5,958	$2,138	$782	$120	$56
6110	Income Taxes	Input	$740,616	$497,869	$117,075	$82,690	$29,679	$10,858	$1,661	$783
6205	Donations	ad	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	ad	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	ad	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	ad	$0	$0	$0	$0	$0	$0	$0	$0
			$60,552,134	**$35,248,433**	**$9,948,647**	**$11,945,197**	**$1,837,748**	**$675,720**	**$116,622**	**$779,767**
				$60,552,134						

Grouping by Allocator	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 144,488	$ 68,509	$ 32,035	$ 43,886	$ -	$ -	$ 58	$ -
1830	$ 605,601	$ 406,657	$ 90,611	$ 72,504	$ 25,197	$ 9,218	$ 1,414	$ -
1835	$ 898,297	$ 606,877	$ 134,617	$ 103,465	$ 37,508	$ 13,722	$ 2,108	$ -
1840	$ 10,687	$ 7,255	$ 1,604	$ 1,192	$ 447	$ 164	$ 25	$ -
1845	$ 33,209	$ 22,544	$ 4,983	$ 3,704	$ 1,391	$ 509	$ 78	$ -
1850	$ 397,027	$ 270,020	$ 61,719	$ 41,866	$ 16,470	$ 6,025	$ 927	$ -
1855	$ 269,598	$ 198,658	$ 42,106	$ 3,049	$ 18,184	$ 6,652	$ 949	$ -
1860	$ 26,272	$ 15,810	$ 6,619	$ 3,362	$ -	$ -	$ -	$ 480
1815-1855	$ 685,728	$ 461,115	$ 105,507	$ 78,585	$ 28,495	$ 10,425	$ 1,601	$ -
1830 & 1835	$ 674,521	$ 453,912	$ 100,979	$ 79,673	$ 28,100	$ 10,280	$ 1,578	$ -
1840 & 1845	$ 58,608	$ 39,787	$ 8,794	$ 6,537	$ 2,454	$ 898	$ 138	$ -

| | | |

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	60%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	60%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	60%
1835	Overhead Conductors and Devices	DNCP	CCA	60%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	60%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	60%
1840	Underground Conduit	DNCP	CCA	60%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	60%
1840-5	Underground Conduit - Secondary	SNCP	CCS	60%
1845	Underground Conductors and Devices	DNCP	CCA	60%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	60%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	60%
1850	Line Transformers	LTNCP	CCLT	60%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	60%
5010	Load Dispatching	1815-1855 D	1815-1855 C	60%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	60%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	60%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	60%
5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	60%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	60%

5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	60%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	60%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	60%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	60%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	60%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	60%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	60%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	60%
5145	Maintenance of Underground Conduit	1840 D	1840 C	60%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	60%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	60%
5175	Maintenance of Meters		1860 C	100%

2006 COST ALLOCATION INFORMATION FILING
HALDIMAND COUNTY HYDRO INC.
EB-2009-0265
Friday, August 28, 2009
Sheet E2 Allocator Worksheet - First Run 2010 Cost of Service Rate Application

Details:
The worksheet below details how allocators are derived.

			1	2	3	7	8	9	10
Explanation	**ID and Factors**	**Total**	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**	**Embedded Distributor - Hydro One**
Demand Allocators									
1 cp									
Transformation CP	**TCP1**	-	0	0	0	0	0	0	0
Bulk Delivery (SubTransmission) CP	**BCP1**	-	0	0	0	0	0	0	0
Distribution CP (Total System)	**DCP1**	100.00%	56.54%	20.66%	22.71%	0.00%	0.00%	0.09%	0.00%
4 cp									
Transformation CP	**TCP4**	-	0	0	0	0	0	0	0
Bulk Delivery (SubTransmission) CP	**BCP4**	-	0	0	0	0	0	0	0
Distribution CP (Total System)	**DCP4**	100.00%	58.59%	18.19%	22.60%	0.45%	0.08%	0.09%	0.00%
12 cp									
Transformation CP	**TCP12**	-	0	0	0	0	0	0	0
Bulk Delivery (SubTransmission) CP	**BCP12**	-	0	0	0	0	0	0	0
Distribution CP (Total System)	**DCP12**	100.00%	56.74%	17.42%	24.96%	0.66%	0.12%	0.10%	0.00%
NON CO_INCIDENT PEAK									
1 NCP									
Distribution NCP (Total System)	**DNCP1**	100.00%	51.71%	21.20%	27.06%	0.00%	0.00%	0.03%	0.00%
Primary NCP	**PNCP1**	100.00%	46.88%	22.52%	30.56%	0.00%	0.00%	0.04%	0.00%
Line Transformer NCP	**LTNCP1**	100.00%	50.09%	24.07%	25.80%	0.00%	0.00%	0.04%	0.00%
Secondary NCP	**SNCP1**	100.00%	65.32%	26.15%	8.47%	0.00%	0.00%	0.06%	0.00%
4 NCP									
Distribution NCP (Total System)	**DNCP4**	100.00%	52.47%	20.81%	26.68%	0.00%	0.00%	0.03%	0.00%
Primary NCP	**PNCP4**	100.00%	47.42%	22.17%	30.37%	0.00%	0.00%	0.04%	0.00%
Line Transformer NCP	**LTNCP4**	100.00%	50.64%	23.68%	25.63%	0.00%	0.00%	0.04%	0.00%
Secondary NCP	**SNCP4**	100.00%	65.88%	25.67%	8.40%	0.00%	0.00%	0.06%	0.00%
12 NCP									
Distribution NCP (Total System)	**DNCP12**	100.00%	52.39%	19.97%	27.60%	0.00%	0.00%	0.04%	0.00%
Primary NCP	**PNCP12**	100.00%	46.51%	21.42%	32.03%	0.00%	0.00%	0.04%	0.00%
Line Transformer NCP	**LTNCP12**	100.00%	49.86%	22.96%	27.13%	0.00%	0.00%	0.04%	0.00%
Secondary NCP	**SNCP12**	100.00%	65.71%	25.22%	9.00%	0.00%	0.00%	0.06%	0.00%
Demand Allocators - Composite									
DEMAND 1815-1855	**1815-1855 D**	100.00%	49.44%	22.76%	27.76%	0.00%	0.00%	0.04%	0.00%
DEMAND 1808	**1808 D**	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1815	**1815 D**	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1820	**1820 D**	100.00%	47.42%	22.17%	30.37%	0.00%	0.00%	0.04%	0.00%
DEMAND 1815 & 1820	**1815 & 1820 D**	100.00%	47.42%	22.17%	30.37%	0.00%	0.00%	0.04%	0.00%
DEMAND 1830	**1830 D**	100.00%	48.52%	22.38%	29.05%	0.00%	0.00%	0.04%	0.00%
DEMAND 1835	**1835 D**	100.00%	49.45%	22.56%	27.96%	0.00%	0.00%	0.04%	0.00%

	1830 & 1835								
DEMAND 1830 & 1835	D	100.00%	48.85%	22.44%	28.67%	0.00%	0.00%	0.04%	0.00%
DEMAND 1840	1840 D	100.00%	50.18%	22.70%	27.08%	0.00%	0.00%	0.04%	0.00%
DEMAND 1845	1845 D	100.00%	50.18%	22.70%	27.08%	0.00%	0.00%	0.04%	0.00%
	1840 & 1845								
DEMAND 1840 & 1845	D	100.00%	50.18%	22.70%	27.08%	0.00%	0.00%	0.04%	0.00%
DEMAND 1850	1850 D	100.00%	50.64%	23.68%	25.63%	0.00%	0.00%	0.04%	0.00%
DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER ALLOCATORS									
Billing Data									
kWh	CEN	100.00%	39.76%	14.29%	25.68%	0.55%	0.10%	0.11%	19.51%
kW	CDEM	100.00%	0.00%	0.00%	51.03%	1.11%	0.20%	0.00%	47.66%
kWh - Excl WMP	CEN EWMP	100.00%	49.40%	17.76%	31.90%	0.68%	0.12%	0.14%	0.00%
Dollar Billed (per 2006 EDR)	CREV	100.00%	67.79%	16.47%	14.72%	0.69%	0.15%	0.18%	0.00%
Bad Debt 3 Year Historical Average	BDHA	100.00%	77.21%	19.18%	3.61%	0.00%	0.00%	0.00%	0.00%
Late Payment 3 Year Historical Average	LPHA	100.00%	75.64%	14.30%	9.49%	0.37%	0.00%	0.19%	0.00%
Number of Bills	CNB	100.00%	85.35%	10.85%	0.66%	0.02%	2.71%	0.37%	0.04%
Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	70.52%	25.80%	3.68%	0.00%
Total Number of Customer	CCA	100.00%	79.49%	10.11%	0.61%	6.90%	2.53%	0.36%	0.00%
Subtransmission Customer Base	CCB	100.00%	0.00%	0.00%	0.00%	70.52%	25.80%	3.68%	0.00%
Primary Feeder Customer Base	CCP	100.00%	79.49%	10.11%	0.61%	6.90%	2.53%	0.36%	0.00%
Line Transformer Customer Base	CCLT	100.00%	79.59%	10.12%	0.49%	6.91%	2.53%	0.36%	0.00%
Secondary Feeder Customer Base	CCS	100.00%	80.82%	8.56%	0.12%	7.40%	2.71%	0.39%	0.00%
Weighted - Services	CWCS	100.00%	73.69%	15.62%	1.13%	6.74%	2.47%	0.35%	0.00%
Weighted Meter -Capital	CWMC	100.00%	60.18%	25.19%	12.80%	0.00%	0.00%	0.00%	1.83%
Weighted Meter Reading	CWMR	100.00%	81.09%	10.65%	7.27%	0.00%	0.00%	0.00%	0.99%
Weighted Bills	CWNB	100.00%	74.34%	18.91%	4.02%	0.02%	2.36%	0.32%	0.03%
CUSTOMER ALLOCATORS - Composite									
CUSTOMER 1815-1855	1815-1855 C	100.00%	79.11%	10.47%	0.60%	6.93%	2.53%	0.36%	0.00%
CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1820	1820 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	1815 & 1820								
CUSTOMER 1815 & 1820	C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1830	1830 C	100.00%	79.57%	10.02%	0.58%	6.93%	2.54%	0.36%	0.00%
CUSTOMER 1835	1835 C	100.00%	79.63%	9.94%	0.56%	6.96%	2.55%	0.36%	0.00%
	1830 & 1835								
CUSTOMER 1830 & 1835	C	100.00%	79.59%	9.99%	0.58%	6.94%	2.54%	0.36%	0.00%
CUSTOMER 1840	1840 C	100.00%	79.69%	9.88%	0.54%	6.98%	2.55%	0.36%	0.00%
CUSTOMER 1845	1845 C	100.00%	79.69%	9.88%	0.54%	6.98%	2.55%	0.36%	0.00%
	1840 & 1845								
CUSTOMER 1840 & 1845	C	100.00%	79.69%	9.88%	0.54%	6.98%	2.55%	0.36%	0.00%
CUSTOMER 1850	1850 C	100.00%	79.59%	10.12%	0.49%	6.91%	2.53%	0.36%	0.00%
CUSTOMER 1855	1855 C	100.00%	73.69%	15.62%	1.13%	6.74%	2.47%	0.35%	0.00%
CUSTOMER 1860	1860 C	100.00%	60.18%	25.19%	12.80%	0.00%	0.00%	0.00%	1.83%
Composite Allocators									
Net Fixed Assets	NFA	100.00%	67.22%	15.81%	11.17%	4.01%	1.47%	0.22%	0.11%
Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	67.32%	15.78%	11.05%	4.04%	1.48%	0.23%	0.10%
5005-5340	O&M	100.00%	69.01%	16.38%	9.81%	2.90%	1.52%	0.23%	0.16%

2010 COST ALLOCATION STUDY

HALDIMAND COUNTY HYDRO INC.

EB-2009-0265

Friday, August 28, 2009

Sheet E3 Demand Allocator Worksheet - First Run 2010 Cost of Service Rate Application

Instructions:
Input sheet for Demand Allocators.

PLCC WATTS
400

		1	2	3	7	8	9	10
Customer Classes	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Embedded Distributor - Hydro One
CCA	23,317	18,534	2,357	143	1,610	589	84	0
CCB	2,283	0	0	0	1,610	589	84	0
CCP	23,317	18,534	2,357	143	1,610	589	84	0
CCLT	23,287	18,534	2,357	113	1,610	589	84	0
CCS	21,763	17,589	1,864	27	1,610	589	84	0
PLCC-CCA	9,327	7,414	943	57	644	236	34	0
PLCC-CCB	913	0	0	0	644	236	34	0
PLCC-CCP	9,327	7,414	943	57	644	236	34	0
PLCC-CCLT	9,315	7,414	943	45	644	236	34	0
PLCC-CCS	8,705	7,036	746	11	644	236	34	0
1NCP								
DNCP1	72,432	37,105	15,208	19,413	542	106	58	0
PNCP1	72,432	37,105	15,208	19,413	542	106	58	0
LTNCP1	68,359	37,105	15,208	15,340	542	106	58	0
SNCP1	51,612	35,213	12,027	3,665	542	106	58	0
PLCC - 1NCP								
DNCP1A	71,750	37,105	15,208	19,413	0	0	24	0
PNCP1A	63,337	29,691	14,265	19,356	0	0	24	0
LTNCP1A	59,276	29,691	14,265	15,295	0	0	24	0
SNCP1A	43,138	28,178	11,281	3,655	0	0	24	0
4 NCP								
DNCP4	273,515	142,103	56,353	72,261	2,163	406	229	0
PNCP4	273,515	142,103	56,353	72,261	2,163	406	229	0
LTNCP4	258,355	142,103	56,353	57,101	2,163	406	229	0
SNCP4	195,865	134,858	44,566	13,644	2,163	406	229	0
PLCC - 4NCP								
DNCP4A	270,812	142,103	56,353	72,261	0	0	95	0
PNCP4A	237,157	112,449	52,582	72,032	0	0	95	0
LTNCP4A	222,046	112,449	52,582	56,921	0	0	95	0
SNCP4A	161,994	106,715	41,584	13,600	0	0	95	0
12NCP								
DNCP12	721,975	374,049	142,604	197,025	6,474	1,164	659	0
PNCP12	721,975	374,049	142,604	197,025	6,474	1,164	659	0
LTNCP12	680,641	374,049	142,604	155,691	6,474	1,164	659	0
SNCP12	513,251	354,977	112,776	37,201	6,474	1,164	659	0
PLCC - 12NCP								
DNCP12A	713,934	374,049	142,604	197,025	0	0	256	0
PNCP12A	612,971	285,086	131,290	196,339	0	0	256	0
LTNCP12A	571,781	285,086	131,290	155,149	0	0	256	0
SNCP12A	411,706	270,550	103,829	37,071	0	0	256	0

2006 COST ALLOCATION INFORMATION FILING

HALDIMAND COUNTY HYDRO INC.

EB-2005-0373 EB-2007-0002

Wednesday, February 28, 2007

Sheet O1 Revenue to Cost Summary Worksheet - Optional Third Run Harmonization of Residential Class

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential - Harmonized	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Norfolk Power	11 Back-up / Standby Power
crev	Distribution Revenue (sale)	$11,788,900	$7,792,703	$1,735,505	$1,879,597	$74,541	$21,198	$20,583	$74,493	$190,280
mi	Miscellaneous Revenue (mi)	$693,828	$511,865	$121,898	$44,658	$2,877	$2,714	$8,385	$20	$1,412
	Total Revenue	$12,482,728	$8,304,568	$1,857,403	$1,924,255	$77,418	$23,912	$28,968	$74,513	$191,692
	Expenses									
di	Distribution Costs (di)	$2,508,299	$1,677,648	$348,587	$267,858	$101,623	$48,835	$5,931	$0	$57,818
cu	Customer Related Costs (cu)	$1,315,743	$992,079	$238,029	$68,719	$652	$2,535	$12,153	$361	$1,216
ad	General and Administration (ad)	$1,443,963	$1,006,347	$220,893	$128,171	$39,415	$19,740	$6,659	$130	$22,607
dep	Depreciation and Amortization (dep)	$2,123,396	$1,422,841	$305,609	$226,043	$80,543	$38,714	$4,750	$1	$44,895
INPUT	PILs (INPUT)	$2,417,761	$1,626,142	$349,252	$251,105	$92,702	$44,557	$5,449	$1	$48,553
INT	Interest	$1,040,211	$699,627	$150,261	$108,035	$39,884	$19,170	$2,344	$1	$20,889
	Total Expenses	$10,849,373	$7,424,684	$1,612,631	$1,049,930	$354,819	$173,551	$37,286	$494	$195,978
	Direct Allocation	$84,722	$0	$0	$0	$0	$0	$0	$84,722	$0
NI	Allocated Net Income (NI)	$1,548,633	$1,041,583	$223,704	$160,838	$59,378	$28,540	$3,490	$1	$31,100
	Revenue Requirement (includes NI)	$12,482,729	$8,466,267	$1,836,335	$1,210,769	$414,197	$202,091	$40,776	$85,216	$227,078
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$33,948,896	$22,819,431	$4,893,549	$3,541,568	$1,302,401	$625,970	$76,440	$16	$689,521
gp	General Plant - Gross	$4,124,930	$2,776,015	$595,712	$426,634	$158,679	$76,269	$9,320	$2	$82,299
accum dep	Accumulated Depreciation	($7,582,952)	($5,075,555)	($1,085,843)	($814,589)	($288,145)	($138,473)	($16,866)	($1)	($163,480)
co	Capital Contribution	($874,545)	($599,260)	($125,369)	($79,023)	($36,996)	($17,779)	($2,132)	$0	($13,985)
	Total Net Plant	$29,616,330	$19,920,630	$4,278,049	$3,074,591	$1,135,939	$545,987	$66,763	$17	$594,355
	Directly Allocated Net Fixed Assets	$218,862	$0	$0	$0	$0	$0	$0	$218,862	$0
COP	Cost of Power (COP)	$26,512,482	$12,566,969	$3,977,087	$8,522,192	$157,675	$35,164	$35,762	$707,830	$509,803
	OM&A Expenses	$5,268,004	$3,676,074	$807,509	$464,748	$141,690	$71,110	$24,743	$490	$81,640
	Directly Allocated Expenses	$36,315	$0	$0	$0	$0	$0	$0	$36,315	$0
	Subtotal	***$31,816,802***	***$16,243,043***	***$4,784,596***	***$8,986,940***	***$299,365***	***$106,275***	***$60,505***	***$744,635***	***$591,444***
	Working Capital	$4,772,520	$2,436,456	$717,689	$1,348,041	$44,905	$15,941	$9,076	$111,695	$88,717
	Total Rate Base	$34,607,713	$22,357,087	$4,995,738	$4,422,632	$1,180,843	$561,928	$75,838	$330,575	$683,071
		Rate Base Input equals Output								

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Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential - Harmonized	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Norfolk Power	11 Back-up / Standby Power
	Equity Component of Rate Base	**$17,303,856**	**$11,178,543**	**$2,497,869**	**$2,211,316**	**$590,422**	**$280,964**	**$37,919**	**$165,287**	**$341,536**
	Net Income on Allocated Assets	**$1,548,633**	**$879,884**	**$244,772**	**$874,325**	**($277,402)**	**($149,639)**	**($8,318)**	**($10,703)**	**($4,286)**
	Net Income on Direct Allocation Assets	**$10,049**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$10,049**	**$0**
	Net Income	**$1,558,681**	**$879,884**	**$244,772**	**$874,325**	**($277,402)**	**($149,639)**	**($8,318)**	**($654)**	**($4,286)**
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES %	**100.00%**	98.09%	101.15%	158.93%	18.69%	11.83%	71.04%	87.44%	84.42%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($1)**	($161,698)	$21,068	$713,486	($336,780)	($178,179)	($11,808)	($10,704)	($35,386)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.01%	7.87%	9.80%	39.54%	-46.98%	-53.26%	-21.94%	-0.40%	-1.25%

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HALDIMAND COUNTY HYDRO INC.

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Sheet O1 Revenue to Cost Summary Worksheet - Optional Third Run Harmonized - Exclude Trx Allowance

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential - Harmonized	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Norfolk Power	11 Back-up / Standby Power
crev	Distribution Revenue (sale)	$11,670,964	$7,792,703	$1,735,505	$1,761,661	$74,541	$21,198	$20,583	$74,493	$190,280
mi	Miscellaneous Revenue (mi)	$693,828	$511,865	$121,898	$44,658	$2,876	$2,714	$8,385	$20	$1,412
	Total Revenue	$12,364,792	$8,304,568	$1,857,403	$1,806,319	$77,417	$23,912	$28,968	$74,513	$191,692
	Expenses									
di	Distribution Costs (di)	$2,390,363	$1,594,069	$330,742	$258,683	$96,857	$46,545	$5,649	$0	$57,818
cu	Customer Related Costs (cu)	$1,315,743	$992,079	$238,029	$68,719	$652	$2,535	$12,153	$361	$1,216
ad	General and Administration (ad)	$1,443,963	$1,005,886	$220,985	$128,618	$38,817	$19,478	$6,761	$134	$23,283
dep	Depreciation and Amortization (dep)	$2,123,396	$1,422,836	$305,610	$226,048	$80,537	$38,711	$4,751	$1	$44,902
INPUT	PILs (INPUT)	$2,417,761	$1,626,137	$349,253	$251,110	$92,696	$44,554	$5,450	$1	$48,561
INT	Interest	$1,040,211	$699,625	$150,262	$108,037	$39,881	$19,169	$2,345	$1	$20,893
	Total Expenses	$10,731,437	$7,340,632	$1,594,880	$1,041,215	$349,440	$170,992	$37,108	$498	$196,672
	Direct Allocation	$84,722	$0	$0	$0	$0	$0	$0	$84,722	$0
NI	Allocated Net Income (NI)	$1,548,633	$1,041,579	$223,705	$160,842	$59,374	$28,538	$3,491	$1	$31,104
	Revenue Requirement (includes NI)	$12,364,793	$8,382,211	$1,818,585	$1,202,056	$408,814	$199,530	$40,599	$85,221	$227,776
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$33,948,896	$22,819,375	$4,893,560	$3,541,622	$1,302,329	$625,938	$76,452	$16	$689,603
gp	General Plant - Gross	$4,124,930	$2,776,006	$595,714	$426,642	$158,669	$76,264	$9,322	$2	$82,311
accum dep	Accumulated Depreciation	($7,582,952)	($5,075,553)	($1,085,843)	($814,591)	($288,143)	($138,472)	($16,866)	($1)	($163,483)
co	Capital Contribution	($874,545)	($599,260)	($125,369)	($79,023)	($36,996)	($17,779)	($2,132)	$0	($13,985)
	Total Net Plant	$29,616,330	$19,920,568	$4,278,061	$3,074,651	$1,135,858	$545,952	$66,776	$18	$594,446
	Directly Allocated Net Fixed Assets	$218,862	$0	$0	$0	$0	$0	$0	$218,862	$0
COP	Cost of Power (COP)	$26,512,482	$12,566,969	$3,977,087	$8,522,192	$157,675	$35,164	$35,762	$707,830	$509,803
	OM&A Expenses	$5,150,069	$3,592,034	$789,756	$456,021	$136,326	$68,558	$24,563	$494	$82,316
	Directly Allocated Expenses	$36,315	$0	$0	$0	$0	$0	$0	$36,315	$0
	Subtotal	***$31,698,866***	***$16,159,003***	***$4,766,843***	***$8,978,212***	***$294,001***	***$103,723***	***$60,325***	***$744,639***	***$592,120***
	Working Capital	$4,754,830	$2,423,850	$715,026	$1,346,732	$44,100	$15,558	$9,049	$111,696	$88,818
	Total Rate Base	$34,590,022	$22,344,419	$4,993,088	$4,421,382	$1,179,959	$561,510	$75,825	$330,576	$683,263
		Rate Base Input equals Output								

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Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential - Harmonized	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load	10 Embedded Distributor - Norfolk Power	11 Back-up / Standby Power
	Equity Component of Rate Base	**$17,295,011**	**$11,172,209**	**$2,496,544**	**$2,210,691**	**$589,979**	**$280,755**	**$37,913**	**$165,288**	**$341,632**
	Net Income on Allocated Assets	**$1,548,633**	**$963,936**	**$262,522**	**$765,104**	**($272,023)**	**($147,080)**	**($8,140)**	**($10,707)**	**($4,980)**
	Net Income on Direct Allocation Assets	**$10,049**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$10,049**	**$0**
	Net Income	**$1,558,681**	**$963,936**	**$262,522**	**$765,104**	**($272,023)**	**($147,080)**	**($8,140)**	**($658)**	**($4,980)**
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES %	**100.00%**	99.07%	102.13%	150.27%	18.94%	11.98%	71.35%	87.44%	84.16%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($1)**	($77,643)	$38,818	$604,263	($331,396)	($175,618)	($11,631)	($10,708)	($36,084)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.01%	8.63%	10.52%	34.61%	-46.11%	-52.39%	-21.47%	-0.40%	-1.46%

Exhibit	Tab	Schedule	Appendix	Contents
8 – Rate Design				
	1	1		Rate Design Overview
			A	Residential Rate Harmonization Calculation Spreadsheet
		2		Rate Mitigation
		3		Other Electricity Charges
		4		Determination of Loss Adjustment Factors
			B	Distribution Loss Assessment Study
			C	Embedded Distributor and Site Specific Loss Factor Study
		5		Existing Rate Classes and Rate Schedule
			D	OEB-Approved Tariff of Rates and Charges Effective May 1, 2009
		6		Schedule of Proposed Rates and Charges
		7		Reconciliation of Rate Class Revenue
		8		Rate and Bill Impacts
			E	Table of Rate and Bill Impacts

RATE DESIGN OVERVIEW

This Exhibit documents the calculation of Haldimand County Hydro Inc's ("HCHI") proposed distribution rates by rate class for the 2010 Test year, based on the allocation of the base revenue requirement across the customer classes according to revenue to cost ratios as proposed in Exhibit 7 – Cost Allocation and rate design as proposed in this Exhibit.

HCHI has determined its total 2010 service revenue requirement to be $13,938,976. The total revenue offsets in the amount of $1,115,334 reduce HCHI's total service revenue requirement to a base revenue requirement to $12,823,642 which is used to determine the proposed distribution rates. The base revenue requirement is derived from HCHI's 2010 capital and operating forecasts, weather normalized usage, forecasted customer counts, calculated PILs and HCHI's regulated return on rate base. The revenue requirement is summarized in Table 1 below:

Table 1
Calculation of Base Revenue Requirement

OM&A Expenses	7,705,417
Amortization Expenses	2,932,087
Total Distribution Expenses	10,637,504
Regulated Return On Capital	2,559,770
PILs	741,703
Service Revenue Requirement	13,938,976
Less: Revenue Offsets	-1,115,334
Base Revenue Requirement	**12,823,642**

The outstanding base revenue requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 7 – Cost Allocation.

Table 2
Proposed Apportionment of Revenue to Rate Classes

Customer Class	2010 Proposed Revenue Allocation	2010 Base Revenue Requirement
Residential	67.79%	8,692,594
G/S < 50 kW	16.47%	2,112,502
G/S 50 to 4999 kW	12.07%	1,548,436
Sentinel Lights	0.58%	74,483
Street Lighting	1.55%	199,036
Unmetered Scattered Load	0.18%	22,822
Embedded Distributor - Hydro One Networks Inc.	1.36%	173,771
	100.00%	12,823,644

HCHI has proposed a re-alignment of the base revenue requirement in Exhibit 7 – Cost Allocation in order to better align the revenue to cost contribution by each customer rate class. Partial reallocation will result in a reduction to the total monthly bill for the G/S 50 to 4999 kW customer rate class and an increase to the Street Lighting and Sentinel Lights customer rate classes. The Sentinel Lights customer will experience the greatest total bill impact of approximately 89.23% based on a common light's billing information. The revenue to cost ratios have been increased in order to comply with the target ranges the Board has set for cost allocation as illustrated in Tables 1 and 2 of Exhibit 7 – Cost Allocation.

It would be inappropriate to leave the revenue to cost ratios as they currently exist and continue to have the other rate classes, specifically the G/S 50 to 4999 kW rate class, subsidize the Street Lighting and Sentinel Lights customer rate classes.

New Rate Class - Embedded Distributor – Hydro One Networks Inc.

As discussed in detail in Exhibit 1, Tab 1, Schedule 12 and further revenue analysis detailed in Exhibit 3, and further allocation of costs detailed in Exhibit 7, Tab 1, Schedule 3, HCHI is proposing a new rate class effective May 1, 2010 to accommodate the Hydro One Networks Inc. ("HONI") embedded situation. HCHI has incorporated HONI's forecasted embedded load and any assets and costs attributable to the embedded situation into the cost allocation model in order to properly match revenues with costs. The Embedded Distributor HONI has been included in all relevant tables in this Exhibit, including revenue to cost ratios, fixed and variable revenue proportions, monthly service charge rate, and distribution volumetric rate, in order to produce distribution rates and bill impacts. Currently, HCHI is charging HONI the OEB-approved for 2009 G/S 50 to 4999 kW rates as mutually agreed to between HCHI and HONI as an interim measure; that is, until HCHI filed their 2010 cost of service rate application to develop a unique rate applicable to HONI as an Embedded Distributor. For purposes of this rate application, distribution revenue and commodity related revenue and charges collected from HONI effective March 7, 2009 for these embedded points has been excluded from all numbers so as not to distort the 2009 Bridge year and the calculation of working capital allowance applicable to the other rate classes.

Rate Harmonization – Residential Rate Class

HCHI has taken this opportunity to harmonize the existing Residential density rate classes – Residential Urban and Residential Suburban – into one rate class. HCHI feels there is no need to carry on with the existing separation of the Residential rate class by Urban and Suburban density criteria. The combined rate class would better reflect the utilization of assets applicable to this class as a whole, as well as establish that the revenue collected from the harmonized class is representative of the costs associated with the "proposed" rate class. The bill impacts generated by this harmonization are minimal as HCHI's current 2009 rates, as set out in Table 3 below,

for the separate urban and suburban density classes are very close to each other for both monthly service charge and distribution volumetric charge.

Table 3
Current 2009 Residential Urban and Suburban Distribution Rates

Current 2009 Rates (Effective May 1, 2009)	Residential Urban	Residential Suburban
Monthly Service Charge (net of Smart Meter Funding Adder)	$10.85	$11.34
Distribution Volumetric	$0.0313 / kWh	$0.0315 / kWh

The intention to harmonize this rate class was previously discussed when the 2007 Cost Allocation Informational Filing was submitted February 28, 2007. The harmonized classification assumes the number of customers of the two separate rate classes are added together to form one rate class and the load data adjusted to reflect the combined load of the two existing classifications. When performing this calculation in the 2007 filing, HCHI noted that the revenue to cost ratio for the harmonized rate class was 98.09% which means the combined revenue from the existing two classifications was essentially in balance with the cost to service the harmonized rate classification. The updated 2010 cost allocation study generates a revenue to cost ratio of 101.01% for the "proposed" harmonized Residential rate class. Refer to Exhibit 7 – Cost Allocation at Tab 1, Schedule 3 for revenue to cost ratios.

In order to generate a "proposed" 2010 harmonized rate for the Residential rate class, HCHI had to harmonize the existing 2009 rates for the separate Urban and Suburban density classes. The historical harmonized rate calculation was performed as far back as the rates approved in the 2006 EDR rate application, the last Board Approved. The 2006 EDR model was used to generate total distribution revenue dollars for the separate classes as one combined rate class. These revenue dollars were then divided

by the combined total customers to generate harmonized 2006 rates. The two rates were calculated as follows:

1. Distribution Volumetric – for each of urban and suburban, an average usage by customer was calculated for the three actual years used in the 2006 EDR model, 2002, 2003, and 2004, and then multiplied by the 2004 customer number to calculate the total consumption (kWh). The kWh was multiplied by the 2006 approved rate for each of Urban and Suburban and then combined to calculate total distribution volumetric dollars and then further divided by the total combined customer kWh to calculate a harmonized volumetric rate.

2. Monthly Service Charge – for each of urban and suburban, the 2004 customer number was multiplied by 12 months in order to annualize and then multiplied by the 2006 approved rate. The combined total dollars was divided by the combined annual customer number to calculate a harmonized service charge rate.

To update the harmonized 2006 distribution rates, the IRM rate models were utilized for each of 2007, 2008, and 2009. In summary, the IRM price cap adjustments, the K-Factor adjustments for capital structure, and the Federal and Ontario tax rate adjustments were all applied in the applicable years as per the IRM models. The final amounts resulted in 2009 harmonized Residential rate class distribution rates to be used for comparison purposes to the "proposed" harmonized 2010 Residential rates. Harmonized rate calculations have been provided in Appendix A to this Exhibit.

Determination of Monthly Fixed / Volumetric Charges

HCHI's current OEB-approved distribution volumetric (net of low voltage charges) and monthly service charges (net of smart meter funding adder) as per the 2009 Tariff of Rates and Charges (EB-2008-0181) for rates effective May 1, 2009 are summarized in Table 4 below.

Table 4
Monthly Fixed & Volumetric Charges (rates effective May 1, 2009)

Customer Class	Monthly Fixed Service Charge (as per 2009 Tariff of Rates and Charges EB-2008-0181)	Smart Meter Funding Adder (as per 2009 OEB Approved Decision EB-2008-0181)	Net Monthly Fixed Service Charge	Distribution Volumetric Charge (as per 2009 Tariff of Rates and Charges EB-2008-0181)	Low Voltage Charge (as per 2009 Tariff of Rates and Charges EB-2008-0181)	Net Distribution Volumetric Charge
Residential - Harmonized **	12.01	1.00	11.01	0.0314	0.0009	0.0305
G/S < 50 kW	19.07	1.00	18.07	0.0228	0.0008	0.0220
G/S 50 to 4999 kW	34.65	1.00	33.65	6.0333	0.3269	5.7064
Sentinel Lights	1.71		1.71	4.6915	0.2822	4.4093
Street Lighting	1.51		1.51	4.1081	0.2430	3.8651
Unmetered Scattered Load	9.03		9.03	0.0235	0.0009	0.0226
Embedded Distributor - Hydro One Networks Inc.	0.00		0.00	0.0000	0.0000	0.0000

** Residential Urban and Residential Suburban rate classes have been harmonized for comparison purposes to the "proposed" 2010 harmonized Residential rate class as per Appendix A.

Using the existing approved monthly service charges applied to the forecast number of customers or connections for 2010, and the approved distribution volumetric charge applied to the forecast volumetric billing determinants, kWh and kW, the following Table 5 outlines the current split between fixed and variable distribution revenue.

Table 5
Current Fixed and Variable Distribution Revenue Proportion

Customer Class	Current Fixed Revenue Proportion	Current Variable Revenue Proportion	Total
Residential	32.14%	67.86%	100.00%
GS < 50 kW	27.61%	72.39%	100.00%
GS 50 to 4999 kW	3.30%	96.70%	100.00%
Sentinel Lights	70.14%	29.86%	100.00%
Street Lighting	67.58%	32.42%	100.00%
Unmetered Scattered Load	45.51%	54.49%	100.00%

HCHI is proposing to change the current fixed / variable proportion for the Residential and G/S < 50 kW rate classes based on a comparison between HCHI and its peer grouping per the OEB consultant's, Pacific Economics Group, LLC ("PEG"), report

dated March 20, 2008. In this report, PEG recommends ranking the performance of distributors based on cost indices, as well as comments on comparing a distributor's OM&A costs per customer to the costs of other distributors in its peer group. If the OM&A cost per customer were to be applied, PEG recommends 12 peer groups based on geographic location, operating scale, and the extent to which a distributor's system is underground. This peer grouping has grouped HCHI in the "Mid-Size Southern Low & Medium Undergrounding" group of distributors. HCHI performed an analysis of the fixed / variable split of the distributors in its peer grouping based on each distributors last OEB approved rate schedule. This analysis generated an average fixed / variable split as follows:

- Residential rate class – Fixed 53.12% / Variable 46.88%
- G/S < 50 kW rate class – Fixed 39.32% / Variable 60.68%

HCHI submits it is appropriate to alter the fixed / variable split of these two rate classes to align itself with its peers. HCHI's current fixed / variable split had become increasingly offside in order to mitigate rates in previous rate applications.

HCHI is also proposing an adjustment to the fixed / variable splits in the G/S 50 to 4999 kW rate class and the Unmetered Scattered Load rate class based on the results of the 2010 cost allocation model. As discussed in detail in Exhibit 7 – Cost Allocation at Tab 1, Schedule 3, HCHI proposes to move the G/S 50 to 4999 kW monthly service charge to the ceiling rate to ensure customer related costs are covered by the appropriate revenue mechanism and to move the Unmetered Scattered Load monthly service charge to the G/S < 50 kW service charge less a metering credit to better represent the costs associated with that rate class.

The following Table 6 provides HCHI's calculations of its proposed fixed / variable split for distribution revenue for all rate classes.

Table 6
Proposed Fixed and Variable Distribution Revenue Proportion

Customer Class	Proposed Fixed Revenue Proportion	Proposed Variable Revenue Proportion	Total
Residential	53.12%	46.88%	100.00%
GS < 50 kW	39.32%	60.68%	100.00%
GS 50 to 4999 kW	11.74%	88.26%	100.00%
Sentinel Lights	70.14%	29.86%	100.00%
Street Lighting	67.58%	32.42%	100.00%
Unmetered Scattered Load	92.34%	7.66%	100.00%
Embedded Distributor - Hydro One Networks Inc.	10.59%	89.41%	100.00%

Proposed Monthly Service Charges

This fixed component of the distribution charge is calculated by dividing the fixed distribution portion of the base revenue requirement by the appropriate 2010 Test Year annualized customer / connection number.

The following Table 7 provides HCHI's calculations of its proposed monthly service charges for the 2010 Test year assuming the proposed fixed / variable split as illustrated in Table 6 above for each rate class.

Table 7
Proposed Monthly Service Charge

Customer Class	Total Base Revenue Requirement	Proposed Fixed Revenue Proportion	2010 Test Year Customer / Connections (Annualized)	Proposed Monthly Service Charge
Residential	$ 8,692,594	53.12%	222,408	$ 20.76
GS < 50 kW	$ 2,112,502	39.32%	28,284	$ 29.37
GS 50 to 4999 kW	$ 1,548,436	11.74%	1,716	$ 105.91
Sentinel Lights	$ 74,483	70.14%	7,068	$ 7.39
Street Lighting	$ 199,036	67.58%	34,548	$ 3.89
Unmetered Scattered Load	$ 22,822	92.34%	1,008	$ 20.91
Embedded Distributor - Hydro One Networks Inc.	$ 173,771	10.59%	96	$ 191.77
Total	$ 12,823,643		295,128	

Proposed Volumetric Charges

The variable component of the distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2010 Test year usage, kWh or kW, as the class charge determinant. This calculation applies to all rate classes with the exception of the G/S > 50 to 4999 kW rate class which includes an adjustment for transformer ownership allowance.

The following Table 8 provides HCHI's calculations of its proposed distribution volumetric charges for the 2010 Test year assuming the proposed fixed / variable split as illustrated in Table 6 above for each rate class.

Table 8
Proposed Distribution Volumetric Charge

Customer Class	Total Base Revenue Requirement	Proposed Variable Revenue Proportion	Transformer Ownership Allowance	2010 Test Year Billing Determinant (kWh / kW)	Unit of Measure	Proposed Distribution Volumetric Charge
Residential	$ 8,692,594	46.88%		169,492,357	kWh	$ 0.0240
GS < 50 kW	$ 2,112,502	60.68%		60,923,412	kWh	$ 0.0210
GS 50 to 4999 kW	$ 1,548,436	88.26%	$ 95,362	296,554	kW	$ 4.9302
Sentinel Lights	$ 74,483	29.86%		1,167	kW	$ 19.0586
Street Lighting	$ 199,036	32.42%		6,475	kW	$ 9.9657
Unmetered Scattered Load	$ 22,822	7.66%		482,264	kWh	$ 0.0036
Embedded Distributor - Hydro One Networks Inc.	$ 173,771	89.41%		276,949	kW	$ 0.5610
Total	$ 12,823,643					

Transformer Ownership Allowance

Currently, HCHI provides a Transformer Ownership Allowance to those customers that own their transformation facilities. HCHI proposes to maintain the current approved transformer ownership allowance of $0.60 per kW which currently only applies to the G/S > 50 to 4999 kW rate class of customers. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the

customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

Proposed Distribution Rates

The following Table 9 sets out HCHI's proposed 2010 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance and excluding the smart meter funding adder, low voltage charge, rate rider for the recovery of deferral and variance account balances and rate rider for the recovery of LRAM and SSM:

Table 9
Proposed 2010 Electricity Distribution Rates

	Fixed Distribution Charge		Variable Distribution Charge	
Customer Class	Customer	Connection	kWh	kW
Residential	$ 20.76		$ 0.0240	
GS < 50 kW	$ 29.37		$ 0.0210	
GS 50 to 4999 kW	$ 105.91			$ 4.9302
Sentinel Lights		$ 7.39		$ 19.0586
Street Lighting		$ 3.89		$ 9.9657
Unmetered Scattered Load		$ 20.91	$ 0.0036	
Embedded Distributor - Hydro One Networks Inc.	$ 191.77			$ 0.5610
Embedded Distributor - Norfolk Power				$ 0.6201

"Legacy" Rate - Embedded Distributor – Norfolk Power

As discussed in detail in Exhibit 1 – Administrative at Tab 1, Schedule 12 and Exhibit 3 – Operating Revenue at Tab 2, Schedule 1, HCHI is requesting the continuation of the legacy Distribution Wheeling Rate of the existing Embedded Distributor – Norfolk Power rate class to compensate for lost revenue from December 12, 2008 forward to the end of December 31, 2010. The original rate setting with the 2006 EDR included two supply

points and has been in effect since May 1, 2006 with adjustments applied at each IRM rate setting and the current rate effective May 1, 2009 is $0.6201 / kW (Table 9 above). Norfolk Power Distribution Inc. ("NPI") reduced the load on the Concession 6 supply point during 2008 and fully eliminated this supply point December 12, 2008. NPI has also advised HCHI that it is their intent to eliminate the other supply point at Highway 6 by the end of 2010. The rate was set with both supply points operating at full load and therefore HCHI requests approval of the existing NPI embedded rate to carry on until the end of 2010. This additional revenue has been excluded from the revenue requirement and used to offset the loss incurred by HCHI for this rate class since 2006, mostly due to NPI's elimination of one supply point on December 12, 2008.

Low Voltage Charges

Low voltage transactions are not part of the electricity wholesale market but rather are specific charges between HONI, as the host distributor, and the LDC for shared low voltage lines and distribution stations. Low voltage ("LV") charges are paid to HONI and recovered from the LDC's customers.

In order to allocate the LV charges appropriately across the customer classes, HCHI has calculated the Retail Transmission Connection charges that would be billed to each customer class based on the 2010 Test Year usage. HCHI finds this approach appropriate based on the OEB decision of December 9, 2004, on Regulatory Assets – Phase II, which directed embedded distributors to use account 1586, RSVA Connection for LV charges from HONI on an interim basis.

HCHI has allocated the LV charges to each customer rate class based on the class proportionate share of the total transmission connection charges for the 2010 Test year. Table 10 below provides the allocation of the LV charges to each customer class.

Table 10
Low Voltage Charges Allocated by Customer Rate Class

Customer Class	Retail Transmission Connection Rate ($) (Current 2009 Rate EB-2008-0181) per KWh	Retail Transmission Connection Rate ($) (Current 2009 Rate EB-2008-0181) per kW	2010 Test Year Usage at 2009 Rates ($)	Allocation Percentages (%)	Allocated LV Charges ($)
Residential	0.0043		728,817.14	49.42%	79,317.75
GS < 50 kW	0.0039		237,601.31	16.11%	25,858.34
G/S 50 to 4999 kW		1.5597	132,850.57	9.01%	14,458.23
G/S 50 to 4999 kW (Interval Metered)		1.7238	364,371.67	24.71%	39,654.86
Sentinel Lights		1.2310	1,436.58	0.10%	156.34
Street Lighting		1.2059	7,808.20	0.53%	849.77
Unmetered Scattered Load	0.0039		1,880.83	0.13%	204.69
TOTALS			**1,474,766.29**	**100.00%**	**160,500.00**

HCHI has calculated the variable LV component to be shown separate on the 2010 Tariff of Rates and Charges based on the allocation in the above Table 10 and 2010 Test year usage. The following Table 11 summarizes the variable charge, the Low Voltage Cost Rate Adder, required to recover the forecasted LV charges.

Table 11
Variable Charge to Recover Low Voltage Charges

Customer Class	Low Voltage Charge Allocated	2010 Test Year Usage (kWh)	2010 Test Year Usage (kW)	Volumetric Rate Billing Determinant	"Proposed" 2010 Low Voltage Rates per kWh	"Proposed" 2010 Low Voltage Rates per kW
Residential	$ 79,317.75	169,492,357		kWh	$ 0.0005	
GS < 50 kW	$ 25,858.34	60,923,412		kWh	$ 0.0004	
G/S 50 to 4999 kW	$ 14,458.23		85,177	kW		$ 0.1825
G/S 50 to 4999 kW (Interval Metered)	$ 39,654.86		211,377	kW		$ 0.1825
Sentinel Lights	$ 156.34		1,167	kW		$ 0.1340
Street Lighting	$ 849.77		6,475	kW		$ 0.1312
Unmetered Scattered Load	$ 204.69	482,264		kWh	$ 0.0004	
TOTALS	**$ 160,500.00**	**343,105,621**	**304,196**			

Proposed Utility – Specific Smart Meter Funding Adder

HCHI has proposed a utility-specific smart meter funding adder of $1.87 per metered customer in order to fund Smart Meter activities. Full details as required by the OEB's Filing Guidelines are in Exhibit 9 – Deferral and Variance Accounts at Tab 2, Schedules 1, 2, and 3.

HCHI anticipates 100% installation of its smart meters just prior to 2010, the rate test year. HCHI does not currently meet the filing requirements to apply for smart meter cost recovery but is requesting a utility-specific smart meter funding adder, in the interim, to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board.

This rate rider would be applicable to the Residential, G/S < 50 kW, and G/S 50 to 4999 kW rate classes. The rate riders are shown in this Exhibit at Tab 1, Schedule 6.

Proposed Deferral and Variance Account Rate Riders

HCHI has requested disposal of certain of its deferral and variance account balances as at December 31, 2008 with projected interest to April 30, 2010 as detailed in Exhibit 9 – Deferral and Variance Accounts at Tab 1, Schedules 2 and 3. The balance requested for disposal is a credit balance in the amount of $225,476, over the default disposition period of one year commencing May 1, 2010, applied as a rate rider to the volumetric distribution charge. This rate rider would effectively provide HCHI's distribution customers with a credit for this one year period.

The proposed rate riders and bill impacts are detailed in Exhibit 9 at Tab 2, Schedule 1 as well as shown in this Exhibit at Tab 1, Schedule 6.

Proposed LRAM and SSM Rate Riders

HCHI is requesting recovery of historical LRAM and SSM amounts related to its third tranche / distribution rates funded CDM programs delivered in the years 2005, 2006 and

2007 as well as LRAM amounts related to OPA funded CDM programs delivered in the years 2006 and 2007. Details of the request and calculations can be found in Exhibit 10 – LRAM and SSM Amounts.

The total combined LRAM (including carrying charges) and SSM amount requested for recovery is $393,490. HCHI is proposing recovery by way of a single volumetric rate rider effective May 1, 2010, which is concurrent with the distribution rate changes, over a one year recovery period ending April 30, 2011.

The proposed rate riders and bill impacts are detailed in Exhibit 10 at Tab 2, Schedule 6 as well as shown in this Exhibit at Tab 1, Schedule 6.

RATE MITIGATION

HCHI submits that the bill impacts of its proposed 2010 electricity distribution rates are not so significant as to warrant any mitigation measures except for the mitigation applied to the Street Lighting and Sentinel Lights rate classes as discussed in Exhibit 7 – Cost Allocation at Tab 1, Schedule 3. The adjustment to the revenue to cost ratios to bring these two classes to the bottom of the Board's target range for these ratios is mitigated over two rate years; that is 2010 and 2011. The offsetting revenue decrease is applied to the G/S 50 to 4999 kW rate class over this same two year period.

OTHER ELECTRICITY CHARGES

HCHI proposes to leave rates for Wholesale Market Service Charge, Rural Rate Protection Charge, and Standard Supply Service – Administrative Charge at rates approved by the OEB in EB-2008-0181 (May 1, 2009 rates).

However, for the Retail Transmission Service Rates ("RTSR's"), Network and Connection charges, HCHI is proposing to adjust the 2009 OEB-approved rates based on the revisions to OEB Guideline G-2008-0001, *Electricity Distribution Retail Transmission Service Rates* issued July 21, 2009 and the requirements in the Filing Guidelines for preparation of this 2010 rate application.

HCHI's adjustment is based on the change to the Ontario Uniform Transmission Rates effective July 1, 2009 and the change to the HONI Transmission Rates effective May 1, 2009 implemented June 1, 2009. HCHI currently pays RTSR's to both the IESO and to HONI that are then passed onto HCHI's customers. As described in Exhibit 1 – Administrative at Tab 1, Schedules 10 and 12, some of the feeders from the 3 transformer stations are owned by HONI and hence HONI is the retail transmission customer at those feeders. HONI would pay the IESO directly the RTSR's on those feeders calculated at the Ontario Uniform Transmission Rates and pass them on to HCHI at HONI's approved rates.

Table 12 below represents the ongoing activity between wholesale network and connection costs and retail billings for the period January 1, 2009 to April 30, 2010. HCHI choose this period to analyze the RTSR's because in Exhibit 9 – Deferral and Variance Accounts, HCHI is requesting disposal of the RSVA accounts, 1584 and 1586, for the variances between cost and revenue associated with the RTSR's for the period January 1, 2005 to December 31, 2008. (RSVA's disposed of as at December 31, 2004 as part of the 2006 EDR rate application) The period January 1, 2009 to April 30, 2010 represents ongoing activity between costs and revenues commencing subsequent to

that disposition period, January 1, 2009, until such time as the RTSR rates can be adjusted, May 1, 2010, to compensate for the variances in these RTSR accounts.

Table 12
Retail Transmission Network and Connection Analysis
(January 1, 2009 to April 30, 2010)

	Total Charges (IESO & HONI)	Total Billed / Unbilled	Variance	Cost / Revenue Ratio	Adjustment
Transmission Network Services	$ 2,593,073.00	$ (2,394,645.00)	$ 198,428.00	108.3%	8.3%
Transmission Connection Services	$ 2,368,855.00	$ (2,239,063.00)	$ 129,792.00	105.8%	5.8%
Total RTSR's	**$ 4,961,928.00**	**$ (4,633,708.00)**	**$ 328,220.00**		

Table 13 details the variance analysis by HCHI on the embedded distributor supply points for HONI. This analysis is limited to the period March 7, 2009 to June 30, 2009, the period of time for which HCHI currently has actual data. HCHI feels the adjustment is reasonable since the ending RTSR rates applicable to the Embedded Distributor – Hydro One Networks Inc., as shown in Table 14, are between the Uniform rates charged by the IESO and the rates charged by HONI. HCHI pays RTSR's to both the IESO and to HONI for this embedded distributor load.

Table 13
Embedded Distributor – Hydro One Networks Inc. RTSR Analysis

Summary (Charges vs Billed)	Total Charges	Total Billed / Unbilled	Variance	Cost / Revenue Ratio	Adjustment
Transmission Network Services	$265,850.00	$(211,040.00)	$54,810.00	126.0%	26.0%
Transmission Connection Services	$243,258.00	$(202,970.00)	$40,288.00	119.8%	19.8%
Total RTSR's	**$509,108.00**	**$(414,010.00)**	**$95,098.00**		

The following Table 14 details the existing OEB-approved 2009 rates, the adjustment to the RTSR's for all classes as detailed in Table 12 and Table 13 and the proposed rates by rate class. Bill impacts are shown in this Exhibit in Schedule 6.

Table 14
Calculated 2010 Retail Transmission Service Rates

	Existing Retail Transmission Rates (effective May 1, 2009)		Retail Transmission Rates "Adjustment"		**"Proposed" Retail Transmission Rates (effective May 1, 2010)**	
	Network	Connection	Network	Connection	**Network**	**Connection**
			8.3%	5.8%	**108.3%**	**105.8%**
per kWh						
Residential	$ 0.0047	$ 0.0043	$ 0.0004	$ 0.0002	**$ 0.0051**	**$ 0.0045**
General Service < 50 kW	$ 0.0042	$ 0.0039	$ 0.0003	$ 0.0002	**$ 0.0045**	**$ 0.0041**
Unmetered Scattered Load	$ 0.0042	$ 0.0039	$ 0.0003	$ 0.0002	**$ 0.0045**	**$ 0.0041**
per kW						
General Service 50 to 4999 kW	$ 1.7362	$ 1.5597	$ 0.1439	$ 0.0904	**$ 1.8801**	**$ 1.6501**
General Service 50 to 4999 kW (Interval Metered)	$ 1.8417	$ 1.7238	$ 0.1526	$ 0.0999	**$ 1.9943**	**$ 1.8237**
Sentinel Lights	$ 1.3159	$ 1.2310	$ 0.1090	$ 0.0714	**$ 1.4249**	**$ 1.3024**
Street Lighting	$ 1.3093	$ 1.2059	$ 0.1085	$ 0.0699	**$ 1.4178**	**$ 1.2758**
Embedded Distributor - Norfolk Power	$ 2.6875	$ 2.5293	$ 0.2227	$ 0.1466	**$ 2.9102**	**$ 2.6759**
	Network	Connection	Network	Connection	**Network**	**Connection**
			26.0%	19.8%	**126.0%**	**119.8%**
per kW						
Embedded Distributor - Hydro One Networks Inc.	$ 1.8417	$ 1.7238	0.4783	0.3422	**$ 2.3200**	**$ 2.0660**

DETERMINATION OF LOSS ADJUSTMENT FACTORS

Total Loss Factor

The total loss factor ("TLF") to be applied to customers' consumption based on the average wholesale and retail kWh for the five years 2004 to 2008 was calculated in Kinectrics report K-418006-001-GE-0001, section 4.4 and their figure 8 is copied as Table 15 below.

Table 15
Total Loss Factor Calculations

		2004	2005	2006	2007	2008	5 Year Average	
	Losses in Distributor's System							
A1	"Wholesale" kWh delivered to distributor (higher value)	n/a	n/a	n/a	n/a	n/a	n/a	
A2	"Wholesale" kWh delivered to distributor (lower value)	382,256,439	397,949,707	378,534,757	385,126,910	376,481,614	384,069,885	
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	0	0	0	0	0	0	
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)	382,256,439	397,949,707	378,534,757	385,126,910	376,481,614	384,069,885	
D	"Retail" kWh delivered by distributor	362,334,194	373,431,335	359,311,282	360,337,098	352,084,247	361,499,631	
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	0	0	0	0	0	0	
F	Net "Retail" kWh delivered by distributor (D)-(E)	362,334,194	373,431,335	359,311,282	360,337,098	352,084,247	361,499,631	
G	Loss Factor in distributor's system [(C)/(F)]	1.0550	1.0657	1.0535	1.0688	1.0693	1.0624	
	Losses Upstream of Distributor's System							
H	Supply Facility Loss Factor	1.0052	1.0052	1.0052	1.0052	1.0052	1.0052	
	Total Losses							
I	Total Loss Factor [(G)x(H)]	1.0605	1.0712	1.0590	1.0744	1.0749	1.0680	Secondary
							1.0573	Primary

Supply Facility Loss Factor

The supply facility loss factor (SFLF) calculation as shown in Table 16 below is extracted from Appendix B of Kinectrics report K-418006-001-GE-0001 and represents the losses on supply to HCHI. The SFLF is calculated in accordance with OEB "*Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*" dated May 27, 2009, Appendix 2-Q, item H based upon the weighted average (using kWh for the

full year 2008) of the standard SFLF on each feeder. The resulting SFLF 1.0052 is used in the calculations for the total loss factor above.

Table 16
Supply Facility Loss Factor

	Dunnville TS 31M1	Dunnville TS 31M2	Caledonia TS 27M3	Caledonia TS 27M4	Caledonia TS 27M5	Caledonia TS 27M6	Jarvis TS 57M1	Jarvis TS 57M4	Jarvis TS 57M6	Jarvis TS 57M3	Jarvis TS 57M5	
	1.0045	1.0060	1.0060	1.0045	1.0045	1.0060	1.0045	1.0045	1.0045	1.0060	1.0045	TOTAL
Sub Total	67,927,559	60,526,047	102,315,593	47,170,341	39,171,718	64,399,514	18,245,751	81,850,262	27,840,851	53,542,825	12,934,259	575,924,720
Loss	305,674.01	363,156.28	613,893.56	212,266.53	176,272.73	386,397.08	82,105.88	368,326.18	125,283.83	321,256.95	58,204.16	3,012,837.21
												1.0052

Embedded Distributor - Norfolk Power Loss Factor

As part of its 2006 rate application Haldimand County Hydro received approval for a "Total Loss Factor – Embedded Distributor - Norfolk Power" of 1.0253. This TLF was initially applied to two supply points to Norfolk Power as follows:

- Highway 6 PMU location
- 6th Concession PMU location

Subsequently on December 12, 2008 Norfolk Power eliminated its need for the 6th Concession supply point and also notified Haldimand County Hydro by letter dated January 6, 2009 of its intention to eliminate its need for the Highway 6 supply point "*by the end of 2010*".

Kinectrics report No. K-418006-002-GE-0001, section 3.1 included a recalculated loss factor for the single point of supply to the Highway 6 location using updated loads resulting in an increase in the TLF from 1.0253 to 1.0442.

HCHI is proposing a TLF of 1.0442 for Embedded Distributor – Norfolk Power.

Embedded Distributor – Hydro One Networks Inc. Loss Factor

Effective March 8, 2009 eight (8) wholesale supply points to Hydro One Networks Inc. ("HONI") were de-registered with the IESO and became retail points of supply from Haldimand County Hydro to HONI. On April 24, 2009 Hydro One at Air Products became embedded to HCHI. Kinectrics report No. K-418006-002-GE-001, section 3.2 included the calculation of individual TLFs for each of these 9 supply points as well as a single TLF of 1.0305 for the group based upon the weighted average in accordance with Table 17 below:

Table 17
Embedded Distributor – Hydro One Loss Factor

Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Canadian Gypsum Company	0.0235	0.012	1.0355	1.0060	1.0417	43685559	0.2904	0.3025
5th Line PMU	0.0085	0.012	1.0205	1.0060	1.0266	2686332	0.0179	0.0183
3rd Line PMU	0.0260	0.012	1.0380	1.0060	1.0442	9407734	0.0625	0.0653
4th Line PMU	0.0254	0.012	1.0374	1.0060	1.0436	2521158	0.0168	0.0175
6th Line PMU	0.0314	0.012	1.0434	1.0060	1.0497	2491772	0.0166	0.0174
Georgia Pacific	0.0090	0.012	1.0210	1.0060	1.0271	13971384	0.0929	0.0954
Green's Road PMU	0.0105	0.012	1.0225	1.0060	1.0286	4346460	0.0289	0.0297
Argyle PMU	0.0280	0.012	1.0400	1.0060	1.0462	1045806	0.0070	0.0073
Air Products	0.0047	0.012	1.0167	1.0045	1.0213	70264000	0.4671	0.4771
Sum						150420206		1.0305

The first 8 points of supply noted in Table 17 above were converted from wholesale to retail points of supply at the request of HONI. Their stated intent was to avoid the requirement to replace the Primary Metering Units at these locations in order to make them IESO compliant.

Air Products Canada Ltd. is a large customer of HONI, which is located physically in Haldimand County, and needs additional capacity to accommodate an expansion. It

was agreed that the most cost effective method for supplying this load was for HONI to connect it to the existing 57M1 feeder which is owned by HCHI.

It should be noted that OEB Decision and Order EB-2009-0136 approved the sale of certain lines from HONI to HCHI as well as associated separation work which will, when completed, have the effect of eliminating Argyle PMU and adding its load to Green's Road PMU. Since this will have little or no effect on the TLF of 1.0305, the Kinectrics report was not revised to reflect this change. However, in all other instances in this rate application, the HONI Embedded Distributor rate class uses 8 supply points as the total customer number for this rate class to represent the elimination of the Argyle PMU with the load added to the Green's Road PMU (Customer number of 8 includes the Air Products point).

Haldimand County Hydro is proposing a TLF of 1.0305 for Embedded Distributor – Hydro One Networks Inc.

STATEMENT AS TO WHETHER THE APPLICANT IS EMBEDDED

Although HCHI uses HONI-owned lines to supply its customers at 4 feeder locations - Caledonia TS 27M3, Caledonia TS 27M6, Dunnville TS 31M2, and Jarvis TS 57M3 – HCHI owns the Primary Metering Units (PMUs) at the TS in all 4 instances as its load occurs upstream of the Hydro One load. Consequently HCHI is not considered as embedded to HONI and in fact is applying in this submission for retail rates and loss factors to treat HONI as embedded to HCHI for these same feeders.

MATERIALITY ANALYSIS ON DISTRIBUTION LOSSES

Haldimand County Hydro's proposed Distribution Loss Factor ("DLF") is 1.0624.

HCHI has several initiatives in place which have had and will have the effect of reducing its distribution losses including:

- An aggressive tree trimming program which has the effect of reducing losses due to contact with trees as well as improving reliability.
- All new construction is built to 27.6/16 kV design standards even if the line will initially continue to be operated at 4.16/2.4 kV or 8.3/4.8 kV in preparation for ultimately converting all lines to 27.6/16 kV. This includes the purchase of dual voltage distribution transformers. Actual conversion of lines to the higher 27.6/16 kV occurs when effective to do so from a cost and reliability perspective.
- Consistent with converting lines for operation at 27.6/16 kV, the elimination of distribution substations is part of the initiative and 3 such substations have been eliminated over the past 4 years. The elimination of a substation removes one significant source of losses from the system.
- Wire size is considered by the Engineering Department in designing all projects to ensure line losses are minimized.
- Losses are taken into account when purchasing new transformers and when sizing transformers for new or replacement installations.
- Regular monitoring of feeders occurs to identify imbalances so corrective action may be taken.
- Cooperating with police authorities to indentify and stop theft of power due to grow operations and other types of power theft.

As noted in Kinectrics report No. K-418006-001-GE-0001 *"Loss levels of 5% are considered to be an OEB threshold. However, this 5% loss level may never be achievable for certain utilities. HCHI is one of Ontario's largest utilities by area at 1252 km^2 with only 12.13 customers per km of line."* However, reducing losses remains an objective at Haldimand County Hydro to make the distribution system efficient and cost effective.

One source of higher losses at HCHI is demonstrated in Kinectrics report No. K-418006-002-GE-0001, section 3.2 where they calculate losses at two Hydro One wholesale points – Springvale PMU and Wainfleet PMU, as follows in Table 18:

Table 18
TLF calculation for Springvale PMU and Wainfleet PMU

Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Springvale PMU	0.0379	0.012	1.0499	1.0060	1.0562	35100000	0.56151	0.5931
Wainfleet PMU	0.0178	0.012	1.0298	1.0060	1.0360	27410000	0.43849	0.4543
Sum						62510000		1.0474

The TLF for these supply points as a group is 1.0474. However, in accordance with OEB "Chapter 2 of the Filing Requirements for Transmission and Distribution Applications" dated May 27, 2009, Appendix 2-Q, item H the average HONI TLF of 1.034 is applied to each of these wholesale supply points, essentially causing higher losses for HCHI than if the site specific TLF was applied.

EXISTING RATE CLASSES AND RATE SCHEDULE

HCHI's existing rate classes and rate schedule have been attached to this Exhibit as Appendix D "Haldimand County Hydro Inc.'s OEB-approved Decision and Order for May 1, 2009 Rates (EB-2008-0181)".

SCHEDULE OF PROPOSED RATE CLASSES, RATES AND CHARGES

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2010 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2010 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2010 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm.

General Service

General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property.

General Service Less Than 50 kW

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 kW to 4,999 kW

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. 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
General Service greater than 1,000 to 5,000 kW interval metered.

Unmetered Scattered Load
This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum 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, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting
This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting.

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. 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.

Embedded Distributor
This classification applies to Norfolk Power Distribution Inc. ("Norfolk Power") effective until December 31, 2010, and Hydro One Networks Inc., both of which are electricity distributors licensed by the Board and provided electricity by means of Haldimand County Hydro Inc.'s distribution facilities.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	20.76
Smart Meter Funding Adder	$	1.87
Distribution Volumetric Rate	$/kWh	0.0240
Low Voltage Cost Rate Adder	$/kWh	0.0005
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0008)
LRAM/SSM Rate Rider – effective until April 30, 2011	$/kWh	0.0022
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	29.37
Smart Meter Funding Adder	$	1.87
Distribution Volumetric Rate	$/kWh	0.0210
Low Voltage Cost Rate Adder	$/kWh	0.0004
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0005)
LRAM/SSM Rate Rider – effective until April 30, 2011	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	105.91
Smart Meter Funding Adder	$	1.87
Distribution Volumetric Rate	$/kW	4.9302
Low Voltage Cost Rate Adder	$/kW	0.1825
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kW	(0.1244)
LRAM/SSM Rate Rider – effective until April 30, 2011	$/kW	0.0414

Retail Transmission Rate – Network Service Rate	$/kW	1.8801
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6501
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.9943
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8237
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	20.91
Distribution Volumetric Rate	$/kWh	0.0036
Low Voltage Cost Rate Adder	$/kWh	0.0004
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0019)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	7.39
Distribution Volumetric Rate	$/kW	19.0586
Low Voltage Cost Rate Adder	$/kW	0.1340
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kW	(2.8645)
Retail Transmission Rate – Network Service Rate	$/kW	1.4249
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	3.89
Distribution Volumetric Rate	$/kW	9.9657
Low Voltage Cost Rate Adder	$/kW	0.1312
Deferral and Variance Account Rate Rider – effective until April 30, 2011	$/kW	(3.1629)
Retail Transmission Rate – Network Service Rate	$/kW	1.4178
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2758
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Embedded Distributor – Norfolk Power – effective until December 31, 2010

Distribution Wheeling Service Rate – Norfolk Power	$/kW	0.6201
Retail Transmission Rate – Network Service Rate – Norfolk Power	$/kW	2.9102
Retail Transmission Rate – Line and Transformation Connection Service Rate – Norfolk Power	$/kW	2.6759

Embedded Distributor – Hydro One Networks Inc.

Service Charge	$	191.77
Distribution Wheeling Service Rate – Hydro One Networks Inc.	$/kW	0.5610
Retail Transmission Rate – Network Service Rate – Hydro One Networks Inc.	$/kW	2.3200
Retail Transmission Rate – Line and Transformation Connection Service Rate – Hydro One Networks Inc.	$/kW	2.0660

Specific Service Charges

Customer Administration		
Legal letter charge	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - 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
Temporary service install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Bell Canada Pole Rentals	$	18.08
Norfolk Pole Rentals – Billed	$	28.61
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)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0680
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0573
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Embedded Distributor - Norfolk Power – effective until December 31, 2010	1.0442
Total Loss Factor – Embedded Distributor – Hydro One Networks Inc.	1.0305

RECONCILIATION OF RATE CLASS REVENUE

HCHI's reconciliation of rate class distribution revenue excludes low voltage charges, smart meter funding adder, deferral and variance account rate riders, and LRAM and SSM rate riders.

2010 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 4,617,190	$ 4,067,817		$ 8,685,007	$ 8,692,594
G/S < 50 kW	$ 830,701	$ 1,279,392		$ 2,110,093	$ 2,112,502
G/S 50 to 4999 kW	$ 181,742	$ 1,462,071	($95,362)	$ 1,548,450	$ 1,548,436
Sentinel Lights	$ 52,241	$ 22,241		$ 74,482	$ 74,483
Street Lighting	$ 134,509	$ 64,528		$ 199,037	$ 199,036
Unmetered Scattered Load	$ 21,075	$ 1,736		$ 22,811	$ 22,822
Embedded Distributor - Hydro One Networks Inc.	$ 18,410	$ 155,368		$ 173,778	$ 173,771
Total	**$ 5,855,868**	**$ 7,053,153**	**($95,362)**	**$ 12,813,658**	**$ 12,823,643**

Difference Due to Rate Rounding
$ 9,985

RATE AND BILL IMPACTS

Appendix E to this Schedule presents the results of the assessment of customer total bill impacts by customer rate class.

Impacts are derived using the applicable May 1, 2009 rates and the proposed 2010 distribution rates, the proposed Deferral and Variance Account rate rider, the proposed new utility-specific smart meter funding adder, the proposed LRAM and SSM rate rider, the proposed low voltage cost rate adder, the proposed retail transmission service rates, and the proposed revised loss factors. Electricity rates across all rate classes are the forecasted rates for 2010 of $0.06072 / kWh.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates and have been presented in the Bill Impact Table as provided by the OEB in the updated Filing Requirements as Appendix 2-R.

SOURCE: EDR 2006 Model
Sheet 6-2 "Demand, Rates"
Sheet 8-5 "Distribution Rates"

	Number of Customers (Connections)			Demand Data - kWh			Demand Data - kW		
	2002 #	2003 #	2004 #	2002 kWh	2003 kWh	2004 kWh	2002 kW	2003 kW	2004 kW
RESIDENTIAL									
Urban	11,814	11,954	12,109	95,868,195	94,104,295	93,420,201			
Suburban	5,593	5,631	5,667	81,549,095	80,917,261	78,828,037			
GENERAL SERVICE									
Less than 50 kW	2,306	2,288	2,303	51,517,777	58,877,719	56,982,950			
Other > 50 kW (specify) .	138	151	150	120,066,374	121,347,276	129,791,532	331,604	329,795	362,779
Other > 50 kW (specify) .Interval meter	0	0	0	0	0	0	0	0	0
Unmetered Scattered Load	89	88	81	510,365	538,961	547,358			
Sentinel Lighting	859	857	729	483,480	587,864	572,369	1,343	1,718	1,578
Street Lighting	2,673	2,713	2,777	2,101,680	2,220,905	2,191,755	5,838	6,047	6,089
TOTALS	23,472	23,682	23,816	352,096,966	358,594,281	362,334,202	338,785	337,560	370,446

		2004 Rates "Sheet 2"			Distribution Rate			Monthly Service Charge		
	Volumetric Rate Type	Distribution Rate kWh $	Distribution Rate kW $	Mthly Service Chrg (Per Cust. or Connection) $	Volumes	"$"	*"Harmonized" Rate*	Volumes	"$"	*"Harmonized" Rate*
RESIDENTIAL										
Urban	kWh	0.0141		9.24	95,668,916	$ 1,348,932		145,308	$ 1,342,646	
Suburban	kWh	0.0152		10.61	80,963,558	$ 1,230,646		68,004	$ 721,522	
					176,632,473	$ 2,579,578	**$ 0.0146**	213,312	$ 2,064,168	**$ 9.68**
GENERAL SERVICE										
Less than 50 kW	kWh	0.0123		12.49						
Other > 50 kW (specify) .	kW		3.4016	23.31						
Other > 50 kW (specify) .Interval meter	kW		3.4016	23.31						
Unmetered Scattered Load	kWh	0.0123		6.24						
Sentinel Lighting	kW		1.5949	1.19						
Street Lighting	kW		1.5966	1.04						

2005 Rates "Sheet 5"

	Volumetric Rate Type	Distribution Rate kWh $	Distribution Rate kW $	Mthly Service Chrg (Per Cust. or Connection) $
RESIDENTIAL				
Urban	kWh	0.0200		9.92
Suburban	kWh	0.0205		11.39
GENERAL SERVICE				
Less than 50 kW	kWh	0.0166		13.65
Other > 50 kW (specify) .	kW		4.2466	25.04
Other > 50 kW (specify) .Interval meter	kW		4.2466	25.04
Unmetered Scattered Load	kWh	0.0166		6.82
Sentinel Lighting	kW		3.3031	1.28
Street Lighting	kW		2.8549	1.12

Distribution Rate

Volumes	"$"	"Harmonized" Rate	
95,668,916	$ 1,913,378		
80,963,558	$ 1,659,753		
176,632,473	$ 3,573,131	$	0.0202

Monthly Service Charge

Volumes	"$"	"Harmonized" Rate	
145,308	$ 1,441,455		
68,004	$ 774,566		
213,312	$ 2,216,021	$	10.39

2006 Rates "Sheet 8-5"

	Volumetric Rate Type	Distribution Rate kWh $	Distribution Rate kW $	Mthly Service Chrg (Per Cust. or Connection) $
RESIDENTIAL				
Urban	kWh	0.0315		11.17
Suburban	kWh	0.0317		11.66
GENERAL SERVICE				
Less than 50 kW	kWh	0.0229		18.42
Other > 50 kW (specify) .	kW		6.0641	34.08
Other > 50 kW (specify) .Interval meter	kW		6.0641	34.08
Unmetered Scattered Load	kWh	0.0237		9.08
Sentinel Lighting	kW		4.7155	1.72
Street Lighting	kW		4.1290	1.52

Distribution Rate

Volumes	"$"	"Harmonized" Rate	
95,668,916	$ 3,013,571		
80,963,558	$ 2,566,545		
176,632,473	$ 5,580,116	$	0.0316

Monthly Service Charge

Volumes	"$"	"Harmonized" Rate	
145,308	$ 1,623,090		
68,004	$ 792,927		
213,312	$ 2,416,017	$	11.33

SERVICE CHARGE (Monthly)		(A)	(B)	C = (A-B)	D	E	F	G = (C+D+E+F)	H	I = (G+H)	J	K = (I+J)	
	Metric	**Current Rates**	Smart Meters Rate Adder	**Current Base Rates**	K-Factor Capital Structure Transition	2007 Federal Tax Rate Adjustment	Ontario Capital Tax Adjustment	**Base Rates Prior to Price Cap Adjustment**	Price Cap Adjustment GDP-IPI @ 1.9% X-factor @ -1.0%	**Base Rates After Price Cap Adjustment**	Smart Meters Rate Adder	**FINAL RATES**	*% Change Final Rates versus Current Rates*
		1-May-06			0.0%	0.0%	0.0%		0.9%			***1-May-07***	
Class													
Residential (Harmonized)	Customer - 12 per year	11.330000	0.260000	11.070000	0.000000	0.000000	0.000000	11.070000	0.099630	11.169630	0.260000	**11.43**	0.88%
General Service Less Than 50 kW	Customer - 12 per year	18.420000	0.260000	18.160000	0.000000	0.000000	0.000000	18.160000	0.163440	18.323440	0.260000	**18.58**	0.89%
General Service 50 to 4,999 kW	Customer - 12 per year	34.080000	0.260000	33.820000	0.000000	0.000000	0.000000	33.820000	0.304380	34.124380	0.260000	**34.38**	0.89%
Unmetered Scattered Load	Connection - 12 per year	9.080000		9.080000	0.000000	0.000000	0.000000	9.080000	0.081720	9.161720		**9.16**	0.90%
Sentinel Lighting	Connection - 12 per year	1.720000		1.720000	0.000000	0.000000	0.000000	1.720000	0.015480	1.735480		**1.74**	0.90%
Street Lighting	Connection - 12 per year	1.520000		1.520000	0.000000	0.000000	0.000000	1.520000	0.013680	1.533680		**1.53**	0.90%
DISTRIBUTION VOLUMETRIC RATE													
	Metric												
Class													
Residential (Harmonized)	kWh	0.031600		0.031600	0.000000	0.000000	0.000000	0.031600	0.000284	0.031884		**0.0319**	0.90%
General Service Less Than 50 kW	kWh	0.022900		0.022900	0.000000	0.000000	0.000000	0.022900	0.000206	0.023106		**0.0231**	0.90%
General Service 50 to 4,999 kW	kW	6.064100		6.064100	0.000000	0.000000	0.000000	6.064100	0.054577	6.118677		**6.1187**	0.90%
Unmetered Scattered Load	kWh	0.023700		0.023700	0.000000	0.000000	0.000000	0.023700	0.000213	0.023913		**0.0239**	0.90%
Sentinel Lighting	kW	4.715500		4.715500	0.000000	0.000000	0.000000	4.715500	0.042440	4.757940		**4.7579**	0.90%
Street Lighting	kW	4.129000		4.129000	0.000000	0.000000	0.000000	4.129000	0.037161	4.166161		**4.1662**	0.90%
Embedded Distributor - Norfolk Power Inc.	kW	0.623200		0.623200	0.000000	0.000000	0.000000	0.623200	0.005609	0.628809		**0.6288**	0.90%

RETAIL TRANSMISSION RATES NETWORK SERVICE		A	B	C = (A+B)									
	Metric	**Current Rates**	Uniform Rate % Adjustment	**FINAL RATES**									
		1-May-06	0.0%	***1-May-07***									
Class													
Residential (Harmonized)	kWh	0.005000	0.000000	**0.0050**									0.00%
General Service Less Than 50 kW	kWh	0.004600	0.000000	**0.0046**									0.00%
General Service 50 to 4,999 kW	kW	1.879400	0.000000	**1.8794**									0.00%
General Service 50 to 4,999 kW - Interval Metered	kW	1.993600	0.000000	**1.9936**									0.00%
Unmetered Scattered Load	kWh	0.004600	0.000000	**0.0046**									0.00%
Sentinel Lighting	kW	1.424500	0.000000	**1.4245**									0.00%
Street Lighting	kW	1.417400	0.000000	**1.4174**									0.00%
Embedded Distributor - Norfolk Power Inc.	kW	2.909100	0.000000	**2.9091**									0.00%

RETAIL TRANSMISSION RATES LINE and TRANSFORMATION CONNECTION SERVICE		A	B	C = (A+B)									
	Metric	Current Rates	Uniform Rate % Adjustment	**FINAL RATES**									
			0.0%										
Class													
Residential (Harmonized)	kWh	0.004300	0.000000	**0.0043**									0.00%
General Service Less Than 50 kW	kWh	0.003900	0.000000	**0.0039**									0.00%
General Service 50 to 4,999 kW	kW	1.540000	0.000000	**1.5400**									0.00%
General Service 50 to 4,999 kW - Interval Metered	kW	1.702000	0.000000	**1.7020**									0.00%
Unmetered Scattered Load	kWh	0.003900	0.000000	**0.0039**									0.00%
Sentinel Lighting	kW	1.215400	0.000000	**1.2154**									0.00%
Street Lighting	kW	1.190600	0.000000	**1.1906**									0.00%
Embedded Distributor - Norfolk Power Inc.	kW	2.497300	0.000000	**2.4973**									0.00%

SERVICE CHARGE (Monthly)		(A)	(B)	C = (A-B)	D	E	F	H	H	I = (G+H)	J	K = (I+J)	
	Metric	**Current Rates**	Smart Meters Rate Adder	**Current Base Rates**	K-Factor Capital Structure Transition	2008 Federal Tax Rate Adjustment	Ontario Capital Tax Adjustment	Price Cap Adjustment GDP-IPI @ 2.1% X-factor @ -1.0%	Total Price Cap Adjustment	**Base Rates After Price Cap Adjustment**	Smart Meters Rate Adder	**FINAL RATES**	*% Change Final Rates versus Current Rates*
		1-May-07			-0.5%	-2.1%	0.0%	1.1%	-1.5%			***1-May-08***	
Class													
Residential (Harmonized)	Customer - 12 per year	11.430000	0.260000	11.170000					-0.167550	11.002450	0.260000	**11.26**	-1.47%
General Service Less Than 50 kW	Customer - 12 per year	18.580000	0.260000	18.320000					-0.274800	18.045200	0.260000	**18.31**	-1.48%
General Service 50 to 4,999 kW	Customer - 12 per year	34.380000	0.260000	34.120000					-0.511800	33.608200	0.260000	**33.87**	-1.49%
Unmetered Scattered Load	Connection - 12 per year	9.160000		9.160000					-0.137400	9.022600		**9.02**	-1.50%
Sentinel Lighting	Connection - 12 per year	1.740000		1.740000					-0.026100	1.713900		**1.71**	-1.50%
Street Lighting	Connection - 12 per year	1.530000		1.530000					-0.022950	1.507050		**1.51**	-1.50%
DISTRIBUTION VOLUMETRIC RATE													
	Metric												
Class													
Residential (Harmonized)	kWh	0.031900		0.031900					-0.000479	0.031422		**0.0314**	-1.50%
General Service Less Than 50 kW	kWh	0.023100		0.023100					-0.000347	0.022754		**0.0228**	-1.50%
General Service 50 to 4,999 kW	kW	6.118700		6.118700					-0.091781	6.026920		**6.0269**	-1.50%
Unmetered Scattered Load	kWh	0.023900		0.023900					-0.000359	0.023542		**0.0235**	-1.50%
Sentinel Lighting	kW	4.757900		4.757900					-0.071369	4.686532		**4.6865**	-1.50%
Street Lighting	kW	4.166200		4.166200					-0.062493	4.103707		**4.1037**	-1.50%
Embedded Distributor - Norfolk Power Inc.	kW	0.628800		0.628800					-0.009432	0.619368		**0.6194**	-1.50%

RETAIL TRANSMISSION RATES NETWORK SERVICE		A	B	C = (A+B)									
	Metric	**Current Rates**	Uniform Rate % Adjustment	**FINAL RATES**									
		1-May-07	-17.0%	***1-May-08***									
Class													
Residential (Harmonized)	kWh	0.005000	(0.000850)	**0.0042**									-17.00%
General Service Less Than 50 kW	kWh	0.004600	(0.000782)	**0.0038**									-17.00%
General Service 50 to 4,999 kW	kW	1.879400	(0.319498)	**1.5599**									-17.00%
General Service 50 to 4,999 kW - Interval Metered	kW	1.993600	(0.338912)	**1.6547**									-17.00%
Unmetered Scattered Load	kWh	0.004600	(0.000782)	**0.0038**									-17.00%
Sentinel Lighting	kW	1.424500	(0.242165)	**1.1823**									-17.00%
Street Lighting	kW	1.417400	(0.240958)	**1.1764**									-17.00%
Embedded Distributor - Norfolk Power Inc.	kW	2.909100	(0.494547)	**2.4146**									-17.00%

RETAIL TRANSMISSION RATES LINE and TRANSFORMATION CONNECTION SERVICE		A	B	C = (A+B)									
	Metric	Current Rates	Uniform Rate % Adjustment	**FINAL RATES**									
			-4.0%										
Class													
Residential (Harmonized)	kWh	0.004300	(0.000172)	**0.0041**									-4.00%
General Service Less Than 50 kW	kWh	0.003900	(0.000156)	**0.0037**									-4.00%
General Service 50 to 4,999 kW	kW	1.540000	(0.061600)	**1.4784**									-4.00%
General Service 50 to 4,999 kW - Interval Metered	kW	1.702000	(0.068080)	**1.6339**									-4.00%
Unmetered Scattered Load	kWh	0.003900	(0.000156)	**0.0037**									-4.00%
Sentinel Lighting	kW	1.215400	(0.048616)	**1.1668**									-4.00%
Street Lighting	kW	1.190600	(0.047624)	**1.1430**									-4.00%
Embedded Distributor - Norfolk Power Inc.	kW	2.497300	(0.099892)	**2.3974**									-4.00%

SERVICE CHARGE (Monthly)		(A)	(B)	C = (A-B)	D	E	F	G = (C+D+E+F)	H	I = (G+H)	J	K = (I+J)	
	Metric	**Current Rates**	Smart Meters Rate Adder	**Current Base Rates**	K-Factor Capital Structure Transition	2009 Federal Tax Rate Adjustment	Ontario Capital Tax Adjustment	**Base Rates Prior to Price Cap Adjustment**	Price Cap Adjustment GDP-IPI @ 2.3% X-factor @ -1.0%	**Base Rates After Price Cap Adjustment**	Smart Meters Rate Adder	**FINAL RATES**	*% Change Final Rates versus Current Rates*
		1-May-08			-0.5%	-0.4%	-0.3%		1.3%			***1-May-09***	
Class													
Residential (Harmonized)	Customer - 12 per year	11.260000	0.260000	11.000000	(0.055000)	(0.044000)	(0.030623)	10.870377	0.141315	11.011692	1.000000	**12.01**	6.68%
General Service Less Than 50 kW	Customer - 12 per year	18.310000	0.260000	18.050000	(0.090250)	(0.072200)	(0.050249)	17.837301	0.231885	18.069186	1.000000	**19.07**	4.15%
General Service 50 to 4,999 kW	Customer - 12 per year	33.870000	0.260000	33.610000	(0.168050)	(0.134440)	(0.093566)	33.213944	0.431781	33.645725	1.000000	**34.65**	2.29%
Unmetered Scattered Load	Connection - 12 per year	9.020000		9.020000	(0.045100)	(0.036080)	(0.025111)	8.913709	0.115878	9.029588		**9.03**	0.11%
Sentinel Lighting	Connection - 12 per year	1.710000		1.710000	(0.008550)	(0.006840)	(0.004760)	1.689850	0.021968	1.711818		**1.71**	0.11%
Street Lighting	Connection - 12 per year	1.510000		1.510000	(0.007550)	(0.006040)	(0.004204)	1.492206	0.019399	1.511605		**1.51**	0.11%
DISTRIBUTION VOLUMETRIC RATE													
	Metric												
Class													
Residential (Harmonized)	kWh	0.031400		0.031400	(0.000157)	(0.000126)	(0.000087)	0.031030	0.000403	0.031433		**0.0314**	0.11%
General Service Less Than 50 kW	kWh	0.022800		0.022800	(0.000114)	(0.000091)	(0.000063)	0.022531	0.000293	0.022824		**0.0228**	0.11%
General Service 50 to 4,999 kW	kW	6.026900		6.026900	(0.030135)	(0.024108)	(0.016778)	5.955880	0.077426	6.033306		**6.0333**	0.11%
Unmetered Scattered Load	kWh	0.023500		0.023500	(0.000118)	(0.000094)	(0.000065)	0.023223	0.000302	0.023525		**0.0235**	0.11%
Sentinel Lighting	kW	4.686500		4.686500	(0.023433)	(0.018746)	(0.013047)	4.631275	0.060207	4.691481		**4.6915**	0.11%
Street Lighting	kW	4.103700		4.103700	(0.020519)	(0.016415)	(0.011424)	4.055342	0.052719	4.108062		**4.1081**	0.11%
Embedded Distributor - Norfolk Power Inc.	kW	0.619400		0.619400	(0.003097)	(0.002478)	(0.001724)	0.612101	0.007957	0.620058		**0.6201**	0.11%

RETAIL TRANSMISSION RATES NETWORK SERVICE		A	B	C = (A+B)									
	Metric	**Current Rates**	Uniform Rate % Adjustment	**FINAL RATES**									
		1-May-08	11.3%	***1-May-09***									
Class													
Residential (Harmonized)	kWh	0.004200	0.000475	**0.0047**									11.30%
General Service Less Than 50 kW	kWh	0.003800	0.000429	**0.0042**									11.30%
General Service 50 to 4,999 kW	kW	1.559900	0.176269	**1.7362**									11.30%
General Service 50 to 4,999 kW - Interval Metered	kW	1.654700	0.186981	**1.8417**									11.30%
Unmetered Scattered Load	kWh	0.003800	0.000429	**0.0042**									11.30%
Sentinel Lighting	kW	1.182300	0.133600	**1.3159**									11.30%
Street Lighting	kW	1.176400	0.132933	**1.3093**									11.30%
Embedded Distributor - Norfolk Power Inc.	kW	2.414600	0.272850	**2.6875**									11.30%

RETAIL TRANSMISSION RATES LINE and TRANSFORMATION CONNECTION SERVICE		A	B	C = (A+B)									
	Metric	Current Rates	Uniform Rate % Adjustment	**FINAL RATES**									
			5.5%										
Class													
Residential (Harmonized)	kWh	0.004100	0.000226	**0.0043**									5.50%
General Service Less Than 50 kW	kWh	0.003700	0.000204	**0.0039**									5.50%
General Service 50 to 4,999 kW	kW	1.478400	0.081312	**1.5597**									5.50%
General Service 50 to 4,999 kW - Interval Metered	kW	1.633900	0.089865	**1.7238**									5.50%
Unmetered Scattered Load	kWh	0.003700	0.000204	**0.0039**									5.50%
Sentinel Lighting	kW	1.166800	0.064174	**1.2310**									5.50%
Street Lighting	kW	1.143000	0.062865	**1.2059**									5.50%
Embedded Distributor - Norfolk Power Inc.	kW	2.397400	0.131857	**2.5293**									5.50%

DISTRIBUTION VOLUMETRIC RATE		(A)	(B)	C = (A-B)	D	E	F	G = (C+D+E+F)	H	I = (G+H)	J	K = (I+J)	
LOW VOLTAGE CHARGES INCLUDED IN DISTRIBUTION VOLUMETRIC RATES	Metric	**Current Rates**	Smart Meters Rate Adder	**Current Base Rates**	K-Factor Capital Structure Transition	2009 Federal Tax Rate Adjustment	Ontario Capital Tax Adjustment	**Base Rates Prior to Price Cap Adjustment**	Price Cap Adjustment GDP-IPI @ 2.3% X-factor @ -1.0%	**Base Rates After Price Cap Adjustment**	Smart Meters Rate Adder	**FINAL RATES**	*% Change Final Rates versus Current Rates*
		1-May-08			-0.5%	-0.4%	-0.3%		1.3%			***1-May-09***	
Class													
Residential (Harmonized)	kWh	0.000900		0.000900	(0.000005)	(0.000004)	(0.000003)	0.000889	0.000012	0.000901		**0.0009**	0.11%
General Service Less Than 50 kW	kWh	0.000800		0.000800	(0.000004)	(0.000003)	(0.000002)	0.000791	0.000010	0.000801		**0.0008**	0.11%
General Service 50 to 4,999 kW	kW	0.326600		0.326600	(0.001633)	(0.001306)	(0.000909)	0.322751	0.004196	0.326947		**0.3269**	0.11%
Unmetered Scattered Load	kWh	0.000900		0.000900	(0.000005)	(0.000004)	(0.000003)	0.000889	0.000012	0.000901		**0.0009**	0.11%
Sentinel Lighting	kW	0.281900		0.281900	(0.001410)	(0.001128)	(0.000785)	0.278578	0.003622	0.282200		**0.2822**	0.11%
Street Lighting	kW	0.242700		0.242700	(0.001214)	(0.000971)	(0.000676)	0.239840	0.003118	0.242958		**0.2430**	0.11%

		FINAL RATES	*"Adders" included in Final Rates*		BASE RATES
			SMART METER FUNDING ADDER	LOW VOLTAGE CHARGE	
		1-May-09	*1-May-09*	*1-May-09*	*1-May-09*
SERVICE CHARGE (Monthly)	Metric				
Class					
Residential (Harmonized)	Customer - 12 per year	**12.01**	**1.00**		**11.01**
General Service Less Than 50 kW	Customer - 12 per year	**19.07**	**1.00**		**18.07**
General Service 50 to 4,999 kW	Customer - 12 per year	**34.65**	**1.00**		**33.65**
Unmetered Scattered Load	Connection - 12 per year	**9.03**			**9.03**
Sentinel Lighting	Connection - 12 per year	**1.71**			**1.71**
Street Lighting	Connection - 12 per year	**1.51**			**1.51**
DISTRIBUTION VOLUMETRIC RATE	Metric				
Class					
Residential (Harmonized)	kWh	**0.0314**		**0.0009**	**0.0305**
General Service Less Than 50 kW	kWh	**0.0228**		**0.0008**	**0.0220**
General Service 50 to 4,999 kW	kW	**6.0333**		**0.3269**	**5.7064**
Unmetered Scattered Load	kWh	**0.0235**		**0.0009**	**0.0226**
Sentinel Lighting	kW	**4.6915**		**0.2822**	**4.4093**
Street Lighting	kW	**4.1081**		**0.2430**	**3.8651**
Embedded Distributor - Norfolk Power Inc.	kW	**0.6201**			**0.6201**

DISTRIBUTION LOSS ASSESSMENT

AT HALDIMAND COUNTY HYDRO INC.

Kinectrics Inc. Report No: K-418006-001-GE-0001

August 10, 2009

Gary Ebersberger
Principal – Asset Management
Transmission and Distribution Technologies

Ray Piercy
Senior Engineer
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DISTRIBUTION LOSS ASSESSMENT

AT HALDIMAND COUNTY HYDRO INC.

Kinectrics Inc. Report No: K-418006-001-GE-0001

August 10, 2009

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Dated: Aug. 12, 2009.

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Haldimand Country Hydro Inc, dated February 2009.

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REVISIONS

Revision Number	Date	Comments	Approved

DISTRIBUTION LOSS ASSESSMENT AT HALDIMAND COUNTY HYDRO INC.

Kinectrics Inc. Report No: K-418006-001-GE-0001

August 10, 2009

EXECUTIVE SUMMARY

As part of the support for its 2010 cost of service rate application to the Ontario Energy Board, Haldimand County Hydro Inc. (HCHI) requested a study of the energy losses on its electric power distribution system.

The method based on subtraction of energy sold from energy purchased is the traditional method outlined by the OEB, and is the method implemented in this report.

Total Losses result from Technical Losses (Conductor and Transformer Inefficiency) and Non-Technical Losses (Theft, meter inaccuracies, billing errors and fraud.)

The recommendations are:

1) The loss factors proposed for inclusion in the 2010 OEB rate application are:

Total Loss Factor – Secondary Metered Customer < 5000kW	**1.0680**
Total Loss Factor – Secondary Metered Customer > 5000kW	**n/a**
Total Loss Factor – Primary Metered Customer < 5000kW	**1.0573**
Total Loss Factor – Primary Metered Customer > 5000kW	**n/a**

2) Even when 5 year averaging is implemented as per OEB guidelines, a slight deteriorating loss trend is noted in the last five years. Therefore, further study is recommended to explore loss reduction mechanisms available to HCHI, as outlined in this report.

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KINECTRICS

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DISTRIBUTION LOSS ASSESSMENT AT HALDIMAND COUNTY HYDRO INC.

1. INTRODUCTION

1.1 Definition of Terms

Total Loss Factor (TLF)
A factor used to increase the measured energy from a customer's meter to account for total losses in the delivery of the energy. Strictly speaking it should be a value with no units such as 1.08 but it is often expressed as a percentage using just the decimal part, for example 1.08 is expressed as 8%. It includes Supply Facilities Loss Factor (SFLF) and Distribution Loss Factor (DLF), and is calculated as: TLF=SFLF x DLF

Supply Facilities Loss Factor (SFLF)
A value multiplied by the DLF to account for loss in the TS transformer.
If directly connected to IESO controlled grid, SFLF = 1.0045.
If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface x loss factor re losses in host distributor's system. If host distributor is Hydro One, SFLF = 1.0060 x 1.0278 = 1.0340 for non-express feeder and 1.006 for express feeder.
If partially embedded, SFLF is weighted average of above.

Distribution Loss Factor (DLF) is a factor by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.

Total Losses
Total losses are the sum of technical and non-technical losses.

Technical Losses
Power or energy used in the components of the system that delivers electricity to the customer's meter. This includes conductor losses that depend on resistance and current and transformer losses that include a conductor loss and a core loss. The core loss does not vary with loading.

Power losses are expressed in kW or as a % of the loss at peak load.
Energy losses are expressed in kWh per year or as a % of the total energy sold in a year.

Non-Technical Losses
Includes all unaccounted for energy other than technical losses. This can occur through theft, meter inaccuracies, billing errors and fraud.

Unbilled Revenue
Revenue for energy consumed prior to the period end but not billed until the following period.

TLF, SFLF, and DLF are further illustrated in the following schematic diagram. In the diagram "MMP" stands for Metered Market Participant, in this case Haldimand County Hydro Inc.

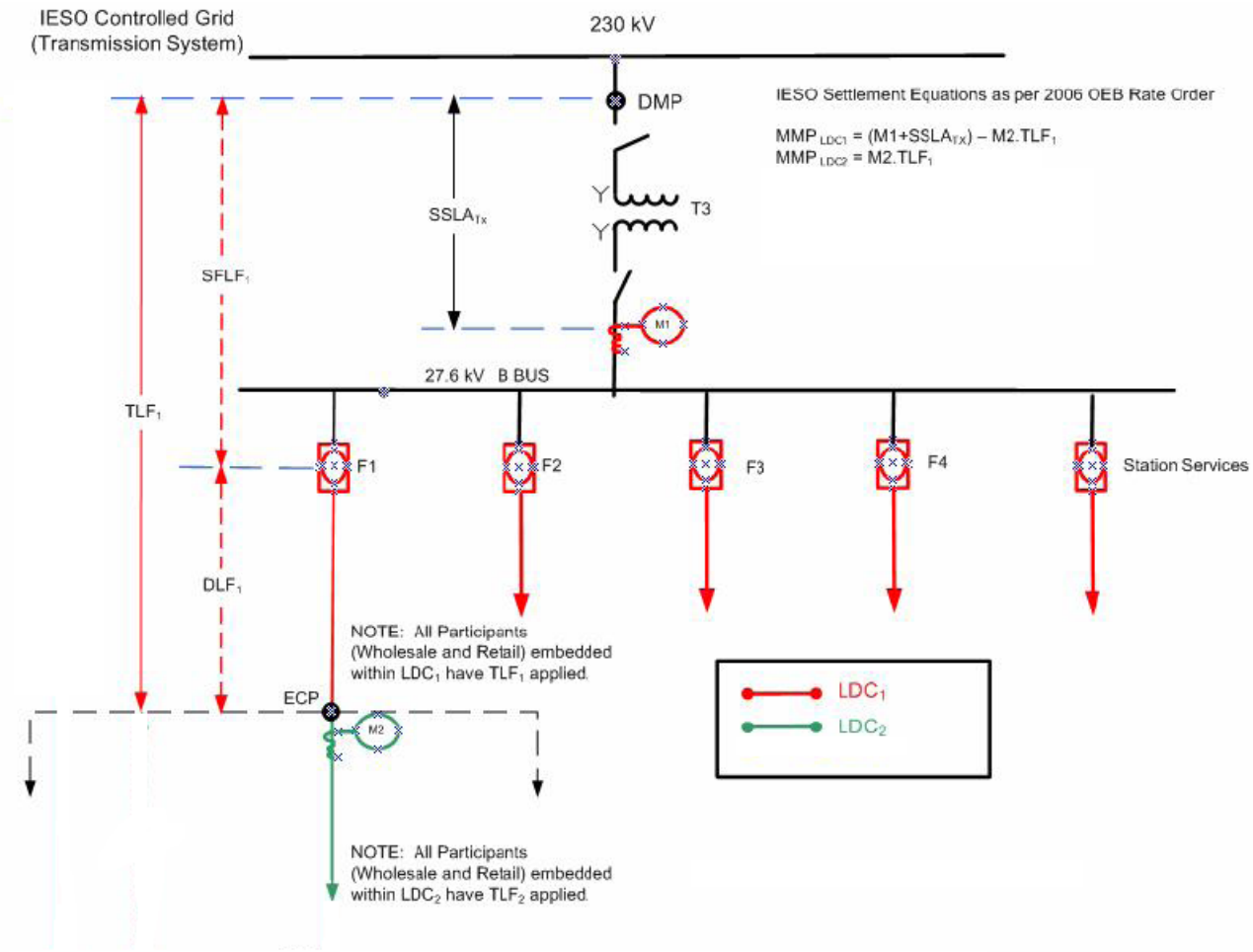


Figure 1 TLF & DLF Schematic *(Source: IESO)*

2. BACKGROUND

Haldimand County Hydro Inc. (HCHI), also referred to as Haldimand County Hydro, requested a study be performed to determine the Total Loss Factors to be submitted in Haldimand County Hydro's 2010 cost of service rate application to the Ontario Energy Board; and, explain the variance from prior OEB-approved total loss factors.

HCHI is a distribution utility with a mixed service area consisting of both rural and small urban areas. Located in Haldimand County along the shore of Lake Erie including the community centres of Caledonia, Cayuga, Dunnville, Hagersville, Jarvis, and Townsend, HCHI serves just over 20,000 customers in both urban and rural settings covering an area of 1252 square kilometres. Its service territory includes urban areas typical of many towns and villages, and rural settlements typical of most farming and seasonal cottage areas.

Distribution losses are calculated by determining the difference between kWh purchased (from the IESO and embedded generators) and kWh sold per retail meter readings, including an adjustment for unbilled revenue to customers, long term load transfers, and unmetered scattered load.
Haldimand County Hydro's total loss factors, as approved by the Ontario Energy Board to be effective May 1, 2006 are:

- 1.0565 for secondary metered customers using less than 5 MW of peak demand load;
- 1.0460 for primary metered customers using less than 5 MW of peak demand load; and
- 1.0253 for embedded distributor - Norfolk Power.

This study covers the years 2002 (Market opening) to 2008 inclusive.

There are variations in total losses and loss factors year-to-year. These are substantially due to the large error that is inevitably introduced through the subtractive technique. There is also a slight worsening trend in losses. The "top-down", subtractive energy method (based on metered data alone) is not able to properly evaluate an optimal loss reduction program.

3. METHODOLOGY

3.1 Present Methodology

There are two basic methods that can be used to calculate technical energy losses:

1. "Top-Down" (A method based on subtraction of metered energy purchased and metered energy sold to customers)

2. "Bottom Up" (A method based on modeling losses in individual components of the system.)

The method based on subtraction of energy sold from energy purchased is the traditional method outlined by the OEB (see Figure 3), and is the method implemented in this report, at HCHI's request.

HCHI's three year average format was OEB compliant at the time of the 2006 rate application. The OEB guidelines have since changed to a five year average format - a value to be held constant in between rate proceedings, as published May 27, 2009, the Ontario Energy Board updated Chapter 2 Filing Requirements for Transmission & Distribution Applications. The OEB approved methodology is presented in Appendix A.

3.2 Limitations on Present Methodology

Distribution losses are calculated by determining the difference between kWh purchased (from the IESO and embedded generators) and kWh sold per retail meter readings, including an adjustment for unbilled revenue to customers, long term load transfers, and unmetered scattered load.

The present OEB methodology has limitations when applied to systems such as HCHI's because HCHI does not recover its actual losses due to subtractive points. The losses at the subtractive points are estimated, but any error in that estimation will result in errors in the overall losses calculated using the input energy values modified by using the subtraction.

The present OEB methodology also provides no indication of the source of the loss, and the method results in a large uncertainty in the loss value due to subtracting two large numbers. This uncertainty is important to understanding the year to year comparisons of calculated losses.

For clarity, subtractive errors are described below. Note how the subtraction of two similar large numbers yields large variability in the resultant. (The error in a subtraction is calculated by adding the absolute errors of the numbers, kW in this example.)
Example with loss = 2%

Parameter	Magnitude	Variation%	Variation
Energy In	20,000 kW	±0.5%	±100 kW
Energy Out	19,600 kW	±0.5%	±98 kW
Loss	400 kW	±49.5%	±198 kW

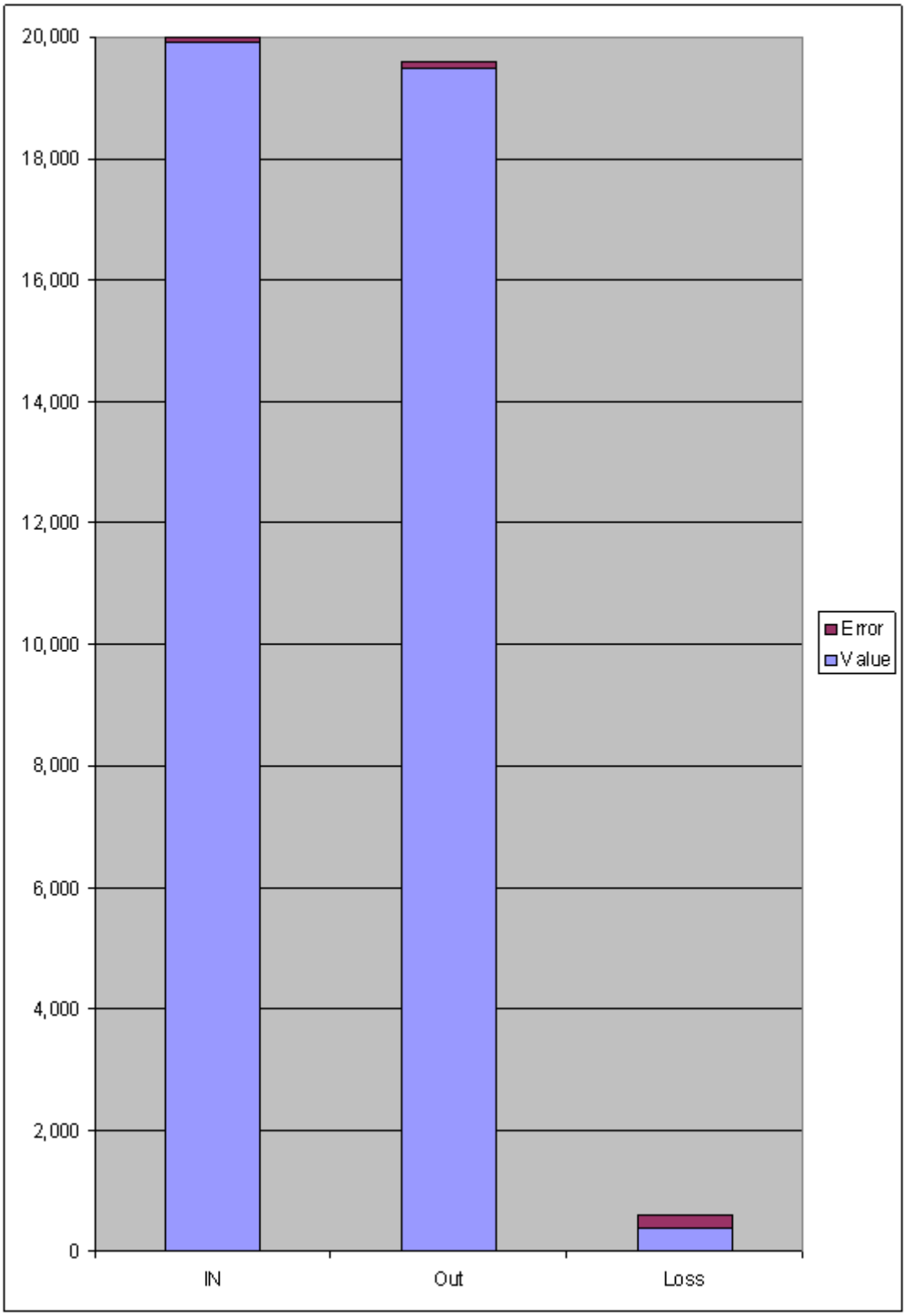


Figure 2 Errors Due to Subtraction

4. CALCULATIONS

4.1 Review of HCHI DLF & TLF methodology from May 1, 2002.

The objective in this component of the report is to review the methodology used to calculate Haldimand County Hydro's Distribution Loss Factor (DLF) and Total Loss Factor (TLF) for each year since Market opening on May 1, 2002 and recommend improvements.

The 2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK gives specific guidance on the determination DLF. Below represents HCHI's calculation submitted to the Ontario Energy Board as schedule 10-5 "Determination of Loss Adjustment factors" as part of their 2006 electricity distribution rate application.

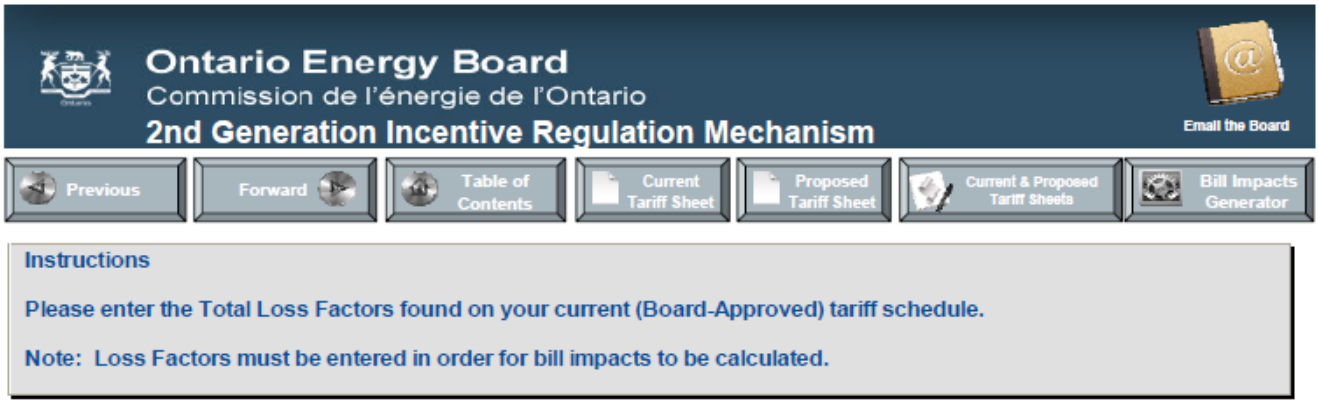
		2002	2003	2004
A	"Wholesale" kWh (IMO)	413,234,501	376,362,131	381,495,946
B	"Wholesale" kWh for Large Use customer(s) (IMO)			
C	Net "Wholesale" kWh (A)-(B)	413,234,501	376,362,131	381,495,946
D	"Retail" kWh (Distributor)	386,303,599	359,532,626	362,334,202
E	"Retail" kWh for Large Use Customer(s) (1% loss)			
F	Net "Retail" kWh (D)-(E)	386,303,599	359,532,626	362,334,202
G	Loss Factor[C/F]	1.0697	1.0468	1.0529
H	Distribution Loss Adjustment Factor (3 year ave.)			1.0565

Figure 3 Calculation for distribution loss adjustment factors

Note that this table results in DLF.

Haldimand County Hydro's total loss factors, as approved by the Ontario Energy Board, to be effective May 1, 2006 are:

- 1.0565 for secondary metered customers using less than 5 MW of peak demand load;
- 1.0460 for primary metered customers using less than 5 MW of peak demand load; and
- 1.0253 for embedded distributor - Norfolk Power.



LOSS FACTORS	Current
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0565
Total Loss Factor - Secondary Metered Customer > 5,000 kW	n/a
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0460
Total Loss Factor - Primary Metered Customer > 5,000 kW	n/a
Total Loss Factor – Embedded Distributor – Norfolk Power	1.0253

Figure 4 2006 HCHI – Approved Loss Factors

4.2 Recalculation of HCHI's DLF &TLF from May 1, 2002 to December 31, 2008

The purpose of this section is a recalculation of HCHI's DLF &TLF from 2002 to December 31, 2008 & comparison with HCHI calculations. The following is a recalculation of HCHI's loss factors, as per OEB guidelines summarized in Appendix A. The results are shown in Figure 5.

The results for DLF from Kinectrics calculations are identical to the results from HCHI's calculations, within the error of the calculation method.

HCHI was approved for the resulting 3 year average DLF (2002 to 2004) of 1.0565 by the OEB as part of their 2006 rate application.

It is important to differentiate between DLF and TLF, as per Figure 1. The calculated DLF as per the 2006 EDR rate application of 1.0565 was incorrectly translated as the TLF on the final approved rate order. The TLF should have been approved as 1.0620 (1.0565 x 1.0052). SFLF is calculated as shown in Appendix B.

Notwithstanding, the DLF and corresponding TLF exceed 5%. The 2006 Rate Handbook requires Applicants that propose a loss factor exceeding 5 percent to provide an explanation for the proposed level and a loss reduction plan.

The losses in HCHI are higher than those in urban utilities because of the large rural area served by HCHI. Rural areas have longer power lines with fewer customers per kilometer of line which increases the line losses. Distribution transformer losses also tend to be higher in rural utilities because of the minimum practical size of distribution transformers.

A telling statistic regarding system losses is the number of customers per km of line. In 2007, HCHI had 12.13 customers per km of line (the provincial average was 23.62 customers per km of line). (Ref. 10)

		2002	2003	2004	2005	2006	2007	2008
	Losses in Distributor's System							
A1	"Wholesale" kWh delivered to distributor (higher value)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
A2	"Wholesale" kWh delivered to distributor (lower value)	377,889,868	377,328,535	382,256,439	397,949,707	378,534,757	385,126,910	376,481,614
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	0	0	0	0	0	0	0
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)	377,889,868	377,328,535	382,256,439	397,949,707	378,534,757	385,126,910	376,481,614
D	"Retail" kWh delivered by distributor	352,096,966	358,594,285	362,334,194	373,431,335	359,311,282	360,337,098	352,084,247
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	0	0	0	0	0	0	0
F	Net "Retail" kWh delivered by distributor (D)-(E)	352,096,966	358,594,285	362,334,194	373,431,335	359,311,282	360,337,098	352,084,247
G	Loss Factor in distributor's system [(C)/(F)]	1.0733	1.0522	1.0550	1.0657	1.0535	1.0688	1.0693
	Losses Upstream of Distributor's System							
H	Supply Facility Loss Factor	1.0052	1.0052	1.0052	1.0052	1.0052	1.0052	1.0052
	Total Losses							
I	Total Loss Factor [(G)x(H)]	1.0788	1.0577	1.0605	1.0712	1.0590	1.0744	1.0749

HCHI Results	1.0733	1.0522	1.0550	1.0657	1.0535	1.0688	1.0693

Figure 5 Recalculation of HCHI's DLF &TLF

4.3 Year to year comparison of losses over the previous six years.

The purpose of this section of the report is a year to year comparison of losses over the previous six years and a report on the causes.

HCHI is concerned about the causes of and reasons for the variations – especially for the anomalous increase in distribution losses between the years 2006 and 2007. One of the obvious contributions is the incorrect application of the DLF for the TLF (as previously noted). Effective May 1, 2006 to present, TLFs have been understated.

It is important to note that year-to year variations, when derived through OEB-mandated 5 year average calculations, are smaller than when based on single year data.

To the extent that variations exist, they can have two causes:

i) Some of the apparent variation could be random error in the measurements, either due to the inherent meter error or the estimation of meters not read precisely at the end of the year (End of Year Effect as a result of unbilled revenue estimations). For example, in 2008 376,481,614 kWh were bought, and 352,084,247 kWh were sold, therefore the loss was 24,397,367 kWh or 7% of energy sold. The inherent metering error in the bought and sold figures will be about +/- 0.5% which is a typical meter accuracy (older residential meters are likely +/- 1%). The +/- 0.5% variation is +/- 1,882,408kWh in the bought and +/-1,760,421 in the sold, for a total error in calculated energy loss of +/-3,642,829 kWh. Taking the years 2005 to 2008 the annual variation in energy loss (max-min) is 5,566,337 kWh. The random error in the meters can account for 65% of this variation (3,642,408 / 5,566,337 = 0.65)

ii) Variations could be real, based on differences in loading. Peak power of the load in a year is only a rough indication of the loss one could expect. If one year has a lower peak each month, but more days and longer hours close to that peak, then higher energy losses may result, despite lower peak power.

Increased energy consumption only generally corresponds to increased losses. The relationship is not a straight line fit – variations exist because peak power and the number of days on peak both have an effect.

iii) HCHI changed from station bus metering to individual feeder metering at all 3 TSs over the years from about 2004 to 2006. The change can contribute to year to year variations. When a bus meter exists the total load loss is correct regardless of the load distribution, since the loss in the station transformer is directly measured in the bus meter reading. However, in the case of individual feeder metering, the loss is estimated assuming a particular load profile over the year. If the actual load profile is different than assumed then the loss value will not be exact. Since the load profile will be different in different years the error in the loss estimate can also vary in different years. (Ref 12)

4.4 Calculation of TLF to be used in HCHI's 2010 rate application to the OEB.

The purpose of this section of the report is a calculation of the TLF to be used in HCHI's 2010 rate application to the OEB.

		2004	2005	2006	2007	2008	5 Year Average	
	Losses in Distributor's System							
A1	"Wholesale" kWh delivered to distributor (higher value)	n/a	n/a	n/a	n/a	n/a	n/a	
A2	"Wholesale" kWh delivered to distributor (lower value)	382,256,439	397,949,707	378,534,757	385,126,910	376,481,614	384,069,885	
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	0	0	0	0	0	0	
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)	382,256,439	397,949,707	378,534,757	385,126,910	376,481,614	384,069,885	
D	"Retail" kWh delivered by distributor	362,334,194	373,431,335	359,311,282	360,337,098	352,084,247	361,499,631	
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	0	0	0	0	0	0	
F	Net "Retail" kWh delivered by distributor (D)-(E)	362,334,194	373,431,335	359,311,282	360,337,098	352,084,247	361,499,631	
G	Loss Factor in distributor's system [(C)/(F)]	1.0550	1.0657	1.0535	1.0688	1.0693	1.0624	
	Losses Upstream of Distributor's System							
H	Supply Facility Loss Factor	1.0052	1.0052	1.0052	1.0052	1.0052	1.0052	
	Total Losses							
I	Total Loss Factor [(G)x(H)]	1.0605	1.0712	1.0590	1.0744	1.0749	1.0680	Secondary
							1.0573	Primary

Figure 5 Loss Calculations, Methodology per Appendix A

5.0 LOSS REDUCTION POTENTIAL

5.1 Determining the source of Losses

The losses in HCHI are higher than those in urban utilities because of the large rural area served by HCHI. Rural areas have longer power lines with fewer customers per kilometer of line which increases the line losses. Distribution transformer losses also tend to be higher in rural utilities because of the minimum practical size of distribution transformers.

HCHI is concerned with a variety of factors regarding the losses in its distribution system, including the level, the trend, the accuracy in calculation and ultimately, the financial implications of the losses in its distribution system.

Loss levels of 5% are considered to be an OEB threshold. However, this 5% loss level may never be achievable for certain utilities. HCHI is one of Ontario's largest utilities by area at 1252 km^2 with only 12.13 customers per km of line (Ref 10). In fact, rural utilities similar to HCHI often experience much higher losses – in the order of 7% to 8% total Technical + Non – Technical losses. A recent study conducted by utilities in North East North America concluded that the technical losses of typical urban utilities range from 2% to 5% of energy sold and for typical rural utilities technical losses range from 4% to 10% of energy sold. It also concluded that the achievable level of energy efficiency is not the same for all utilities but varies depending on the details of the service territory and the past design practices. (Ref. 13) The losses found at HCHI are within this expected range.

Energy losses on power systems can be divided into two broad categories, technical losses and non-technical losses.

TECHNICAL LOSSES

Technical losses on distribution systems are primarily due to I^2R losses in conductors and magnetic losses in transformers.

Transformer losses include no-load losses that are independent of transformer loading and load losses that vary with loading.

Losses are inherent to the distribution of electricity and cannot be eliminated but may be minimized. In order to properly manage the inevitable losses it is necessary to understand the relative impact of different sources of losses. The largest source of losses is not always the easiest to reduce. Some sources can be reduced more cost effectively than others.

Without a bottom up modeling approach we cannot know the causes of the losses, we can only postulate.

A telling statistic regarding system losses is the number of customers per km of line. In 2007, HCHI had 12.13 customers per km of line (the provincial average was 23.62 customers per km of line). (Ref. 10)

Canadian Electricity Association Technologies (CEATI) research has developed loss estimates for "typical" urban and rural distribution systems as shown in the figure below.

	Estimated Loss as a Percent of Energy Sold	
Component	**CEATI Typical Urban**	**CEATI Typical Rural**
Subtransmission Lines	0.1	0.7
Power Transformers	0.1	0.7
Distribution Lines	0.9	2.5
Distribution Transformers No Load	1.2	1.7
Distribution Transformers Load	0.8	0.8
Secondary Lines	0.5	0.9
Total	**3.6**	**7.3**

Figure 6 Typical Technical Loss Values

HCHI has primarily rural distribution with some pockets of urban development.

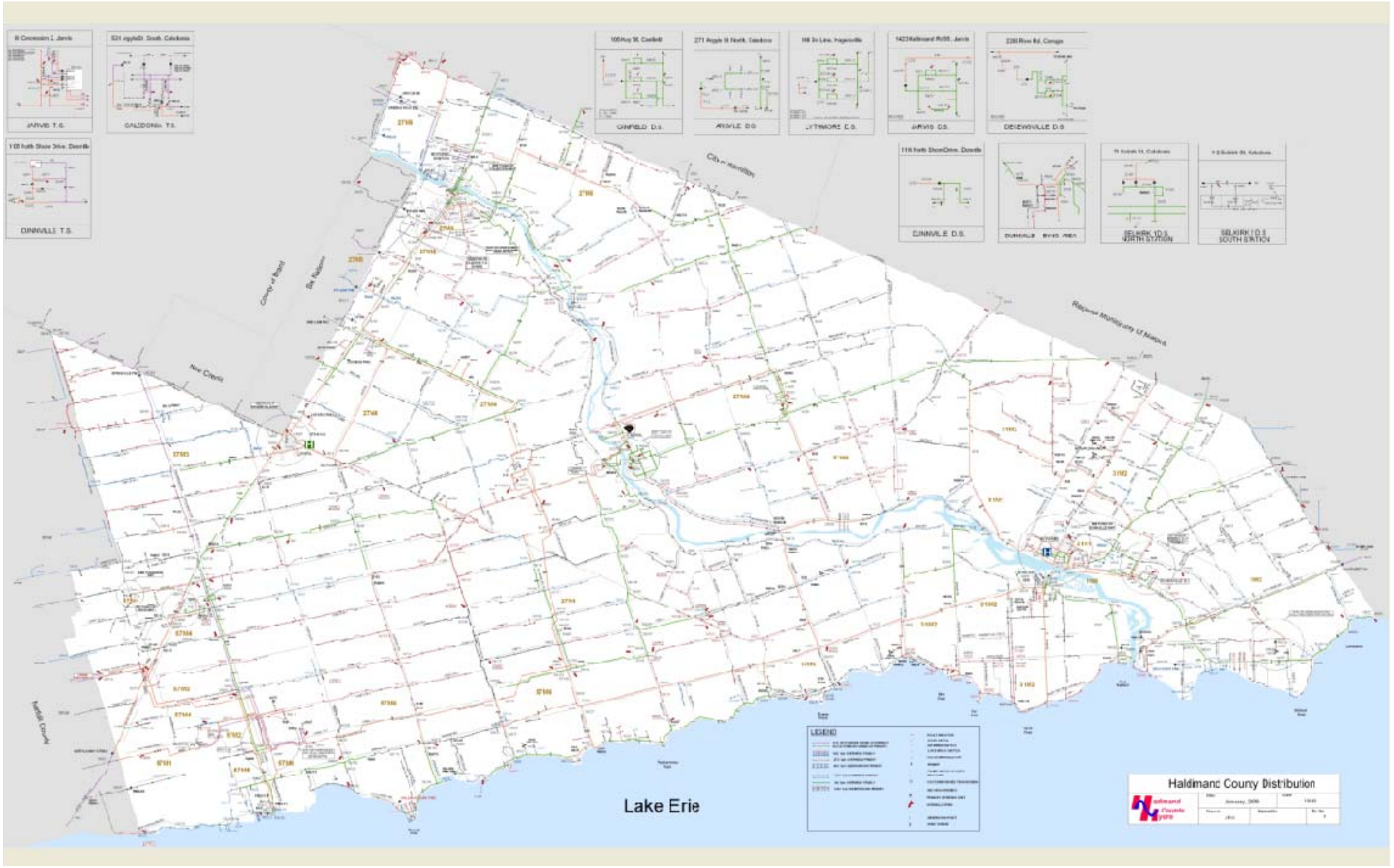


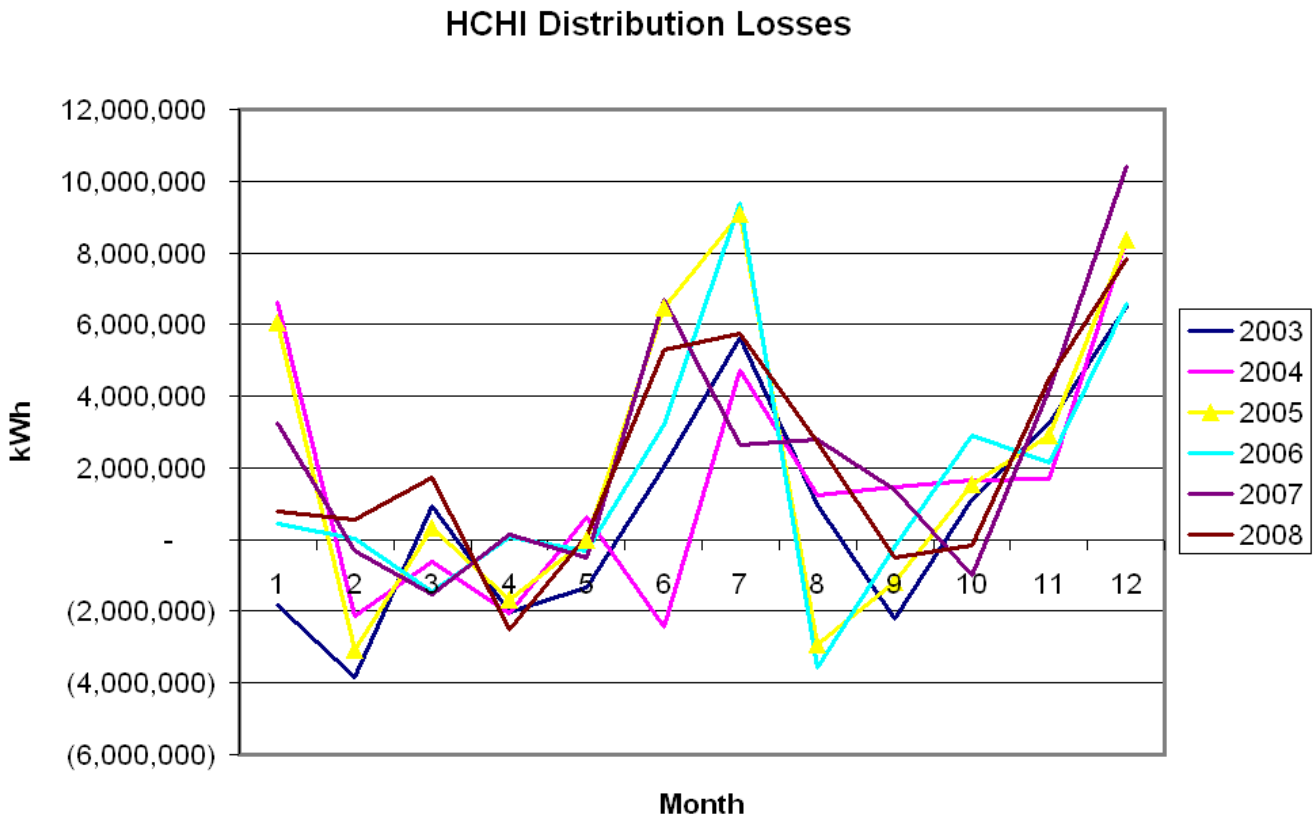
Figure 7 HCHI Service Area - Customer Density is Low.

Technical losses usually exist in the following proportions:

50% on the distribution lines,
14% in the station transformers,
30% in the distribution transformers and
6% on the secondary lines. (Ref 9)

and can be most cost-effectively reduced based on a thorough assessment of specific system parameters.

Losses at HCHI have a clear pattern of loss tracking seasonality. This indicates I^2R loss that is related to power consumption.



HCHI Losses by Month of Year

NON-TECHNICAL LOSSES

Past experience demonstrated that many utilities have used a figure of 10% of the technical losses to estimate non-technical losses.

Non-technical losses occur because of the following:

- Theft, fraud, meter tampering/bypassing
- Faulty meters - resulting in the amount of electricity used being under-recorded.
- Incorrect records, billing errors

Published figures for the level of non-technical losses in North America are very difficult to obtain. Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold and the upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors. (Ref 3)

Indications are I^2R losses are the key drivers in place at HCHI.

5.2 Reducing Losses
Technical Losses minimization

Energy losses are produced by the electrical resistance in distribution system equipment such as cables, conductors, and transformers. The existence of energy losses is an inherent property of power systems and cannot be avoided with present technology. However, the size of these losses can, in many cases, be reduced by applying one or more of several available techniques.

Possible loss minimization methods include capacitor placement, load balancing, transformer sizing and reconductoring of feeders. System reconfiguration is another minimization technique, but depends highly on the topology of the distribution system under consideration.

Technical loss minimization techniques must be evaluated for both technical & economic feasibility before being implemented.

Capacitor Placement
Capacitors reduce feeder losses by providing reactive power compensation. The challenge in capacitor application involves the determination of the location, size, number and type of capacitors to be placed in the system.

Fixed and/or switched capacitors can be used in the system. Fixed shunt capacitors provide constant reactive power compensation and are suitable for loads having approximately constant reactive power requirements. Switched shunt capacitors are used in cases of load variability since they allow more flexibility in controlling the losses and voltage drop.

Load Balancing on Phases
A considerable part of the HCHI distribution system consists of single-phase residential loads, making the power flow in three-phase main feeders difficult to balance. The total I^2R loss in the three phases of an unbalanced system is higher than that of a balanced system, and therefore, balancing the phases, both at planning and operation stages, can result in loss reduction. When new single-phase loads are connected to the system, balancing can be achieved by carefully

selecting the phases to which the loads are to be connected (when a selection possibility exists).

As a distribution system expands, loads become unevenly distributed among the substation transformers. Therefore, some of the station transformers and feeders are heavily loaded while others have enough capacity to take the excessive load. A system reconfiguration can result in more balanced flows in the system, which in turn, leads to reduced system losses. Switching reconfiguration is another cost-effective way of reducing distribution system losses. Remotely controlled switches, would allow the
switching reconfiguration based on daily load patterns.

Transformer Sizing
The series and shunt resistance and reactance of distribution transformers result in significant losses on distribution systems. The consumption of reactive power by transformer reactance introduces higher reactive current flow in the primary circuits, which contributes to the system losses. Distribution system losses can be reduced by properly sizing the distribution transformers.

In general, no-load losses accounted for about 35% of the transformer losses. Transformer no-load losses are constant and depend on the size of the transformer installed and the loss formula to which it was purchased. Decreasing the transformer rating will decrease the no-load losses. Often, the actual peak load on feeders is only a fraction of connected transformer kVA. When this is the case, it implies that the connected kVA is unnecessarily high and a reduction in transformer sizes would not overload the smaller transformers. Review of transformer sizing practices including the cost-of-losses formula, loss-of-life, load growth considerations, and inventory costs would be worthwhile.

The optimal size of distribution transformer for an application can be computed using a computer program such as TRANSIZE. Under the expected loading conditions, the program determines the transformer loss-of-life and the total ownership cost based on capital cost and the present value of the cost of losses.

Another method to apply optimal transformer sizing information would be to pre-calculate the best transformer sizes for a set of expected loading situations, and simply create a chart of optimal transformer sizes for various loading conditions.

Conductor Sizing
The sizing of distribution conductors and cables is normally determined by considering the thermal capability of the conductors and cables, and by the amount of voltage drop from source to the receiving-end. HCHI's long rural feeders are generally voltage drop limited as opposed to ampacity limited. Another consideration, however, is cost of losses related to the conductor size selected. The larger the conductor size, the lower are joule losses. Usually, larger conductors require more capital expenditures and a balance must be found when sizing the conductors. Reconductoring of sections of a
feeder that are heavily loaded can provide loss improvements.

Non-technical Losses minimization

Interviews with HCHI staff reveal that steps have already been taken to reduce errors due to non-technical losses. Specifically, meter errors such as those resulting from inaccurate CTs and PTs have been addressed. Billing accuracy has been tested. In conjunction with known

patterns for non-technical losses in the utility industry as well as the specific pattern of losses at HCHI by season (& with load) imply that the reduction of non-technical losses at HCHI is already optimized.

6. CONCLUSION

HCHI's loss factor recommendations are:

1) The loss factors to be included in the 2010 OEB rate application are:

Total Loss Factor – Secondary Metered Customer < 5000kW	**1.0680**
Total Loss Factor – Secondary Metered Customer > 5000kW	**n/a**
Total Loss Factor – Primary Metered Customer < 5000kW	**1.0573**
Total Loss Factor – Primary Metered Customer > 5000kW	**n/a**

2) Even when 5 year averaging is implemented as per OEB guidelines, a slight deteriorating loss trend is noted. Therefore, further study is recommended to explore loss reduction mechanisms available to HCHI, as outlined in this report. A "bottom up" method (using circuit simulation) is recommended as a loss reduction tool, since it points to specific system components (e.g. transformers & conductors) and results in a prioritized remedial action scheme.

APPENDIX A
LOSS FACTORS
(Reference 11)

Modified Schedule 10-5: Determination of Loss Factors

		Year 1	Year 2	Year 3	Year 4	Year 5	5 Year Average
	Losses in Distributor's System						
A_1	"Wholesale" kWh delivered to distributor (higher value)						
A_2	"Wholesale" kWh delivered to distributor (lower value)						
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)						
C	Net "Wholesale" kWh delivered to distributor (A_2)-(B)						
D	"Retail" kWh delivered by distributor						
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)						
F	Net "Retail" kWh delivered by distributor (D)-(E)						
G	Loss Factor in distributor's system [(C)/(F)]						
	Losses Upstream of Distributor's System						
H	Supply Facility Loss Factor						
	Total Losses						
I	Total Loss Factor [(G)x(H)]						

A_1

- If directly connected to IESO controlled grid, kWh pertain to metering installation on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. This corresponds to the higher of the two kWh values provided by MV-WEB.
- If fully embedded within a host distributor, kWh pertains to virtual metering at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One, kWhs from the Hydro One invoice corresponding to "Total kWh Losses" should be reported. This corresponds to the higher of the two kWh values provided by the Hydro One invoice.

- If partially embedded, kWh pertains to the sum of above.

A_2

- If directly connected to the IESO controlled grid, kWhs pertain to metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. This corresponds to the lower of the two kWh values provided by MV-WEB.
- If fully embedded within a host distributor, kWh pertains to virtual metering at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One, kWh from the Hydro One invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided by the Hydro One invoice.
- If partially embedded, kWh pertains to sum of above.
- Additionally, kWh pertaining to distributed generation should be included in $A_{2.}$

B

- If a Large Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1%, i.e. B = 1.01 x E.

D

- kWhs corresponding to D should equal the total of "total billed energy sales in kWhs for each rate class" in item 1 of Section 2.1.3 in Electricity Reporting and Record Keeping Requirements dated April 4, 2008.

G & I

- This loss factor pertains to secondary metered customers less than 5,000 kW.

H

- If directly connected to IESO controlled grid, SFLF = 1.0045.
- If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface x loss factor re losses in host distributor's system. If host distributor is Hydro One, SFLF = 1.0060 x 1.0278 = 1.0340.
- If partially embedded, SFLF is weighted average of above.

APPENDIX B - CALCULATION OF SFLF

- Requires Hourly Data for all feeders
- Individual Feeder readings are totalled.
- Directly connected feeders have 1.0045 loss factor applied.
- Hydro One Owned feeders are considered express and a 1.006 Loss Factor to be applied.
- 1.034 Loss Factor applies only to non- express feeders: n/a in HCHI service territory.
- Weighted average results in 1.0052 SFLF

This spreadsheet includes all readings for the 24 hours and 366 days in 2008, but is truncated here for clarity. Reads are dimensionless but can be taken as kWh or kW given the 1 hour interval.

		Dunnville TS 31M1	Dunnville TS 31M2	Caledonia TS 27M3	Caledonia TS 27M4	Caledonia TS 27M5	Caledonia TS 27M6	Jarvis TS 57M1	Jarvis TS 57M4	Jarvis TS 57M6	Jarvis TS 57M3	Jarvis TS 57 M5	
		1.0045	1.0060	1.0060	1.0045	1.0045	1.0060	1.0045	1.0045	1.0045	1.0060	1.0045	TOTAL
	Sub Total	67,927,559	60,526,047	102,315,593	47,170,341	39,171,718	64,399,514	18,245,751	81,850,262	27,840,851	53,542,825	12,934,259	575,924,720
	Loss	305,674.01	363,156.28	613,893.56	212,266.53	176,272.73	386,397.08	82,105.88	368,326.18	125,283.83	321,256.95	58,204.16	3,012,837.21
													1.0052
READ_DATE	READ_HR												
1/1/2008	1	6880.99	8033.9	7844.58	6073.46	2793.84	6136.45	2001.47	9650.73	3444.2	5948.42	1258.9	
1/1/2008	2	6508.05	8602.81	7619.36	5695.87	2622.15	5843.42	2582.52	9705.11	3199.7	5844.24	1321.83	
1/1/2008	3	6202.84	8915.05	7343.17	5388.29	2469.77	5492.82	2573.8	9229.69	3039.03	5551.61	1404.17	
1/1/2008	4	6123.53	8869.03	7139.22	5300.54	2226.9	5287.78	2582.33	8877.58	2897.94	5440.22	1365.15	

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EMBEDDED DISTRIBUTOR AND SITE SPECIFIC LOSS FACTORS

Kinectrics Inc. Report No: K-418006-002-GE-0001

August 10, 2009

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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Haldimand County Country Hydro Inc, dated February 2009.

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REVISIONS

Revision Number	Date	Comments	Approved

EMBEDDED DISTRIBUTOR AND SITE SPECIFIC LOSS FACTORS

Kinectrics Inc. Report No: K-418006-002-GE-0001

August 10, 2009

EXECUTIVE SUMMARY

Haldimand County Hydro requested a study be performed to estimate the appropriate loss factors to be applied to an embedded distribution utility and to 11 specific customer locations within its service territory. The loss factors were calculated using spreadsheet based models of each of the circuits serving the specific loads. The models utilize conductor size, conductor length and load data (hourly interval) supplied by Haldimand County Hydro. As for any study of this type, all the detailed data for a completely accurate calculation of loss factors were not available therefore suitable simplifying assumptions and industry typical data were used where necessary. The possible effects of the assumptions have been assessed using a study of the sensitivity of the loss factors to variations in the input data and assumptions.

The recommendations are:

1 The recommended embedded distributor DLF for Norfolk Power is 1.0395 and the TLF is 1.0442. This estimate includes 1.2% for non-technical losses and a supply facilities factor of 1.0045. It is based on the Highway 6 PMU location only because the 6th Line location was removed from service December 12, 2008. The Highway 6 location is planned to be removed in December 2010.

2 The recommended site specific DLFs and TLFs are shown in the following table:

Customer	Distribution Loss Factor (DLF)	Total Loss Factor (TLF)
Canadian Gypsum Company	1.0355	1.0417
5th Line PMU	1.0205	1.0266
3rd Line PMU	1.0380	1.0442
4th Line PMU	1.0374	1.0436
6th Line PMU	1.0434	1.0497
Georgia Pacific	1.0210	1.0271
Green's Road PMU	1.0225	1.0286
Argyle PMU	1.0400	1.0462
Air Products	1.0167	1.0213
Springvale PMU	1.0499	1.0562
Wainfleet PMU	1.0298	1.0360

These values include 1.2% for non-technical losses and a supply facilities factor of 1.006 or 1.0045 as appropriate.

3 If a group rate is established for the first nine load locations the appropriate TLF is an average of the site specific TLFs weighted by the annual energy sold at each site. Based on the 2008 data and with an assumed 8 MW load for Air Products, this value is 1.0305.

If a group rate is established for the last two sites the appropriate TLF, based on 2008 data, is 1.0474

4 The results of this study have an inherent uncertainty due to the modeling used to calculate them. The uncertainty in the technical loss estimates has been estimated to be ±10% and in the TLFs ±20%.

5 The DLF and TLF for the Wainfleet PMU should be recalculated when a full year of data is available with the Mohawk Point wind farm in service. The site specific DLF and TLF could drop by 27% of the value estimated in this report.

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EMBEDDED DISTRIBUTOR AND SITE SPECIFIC LOSS FACTORS

1. INTRODUCTION

1.1 Definition of Terms

Total Loss Factor (TLF)
A factor used to increase the measured energy from a customer's meter to account for total losses in the delivery of the energy. Strictly speaking it should be a value with no units such as 1.08 but it is often expressed as a percentage using just the decimal part, for example 1.08 is expressed as 8%. It includes Supply Facilities Loss Factor (SFLF) and Distribution Loss Factor (DLF), and is calculated as Calculated as: TLF=SFLF x DLF

Supply Facilities Loss Factor (SFLF)
A value added to the DLF to account for loss in the TS transformer.
If directly connected to IESO controlled grid, SFLF = 1.0045.
If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface x loss factor re losses in host distributor's system. If host distributor is Hydro One, SFLF = 1.0060 x 1.0278 = 1.0340 for non-express feeder and 1.006 for express feeder. If partially embedded, SFLF is weighted average of above.

Distribution Loss Factor (DLF) means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.

Total Losses
Total losses are the sum of technical & non-technical losses.

Technical Losses
Power or energy used in the components of the system that delivers electricity to the customer's meter. This includes conductor losses that depend on resistance and current, and transformer losses that include a conductor loss and a core loss. The core loss does not vary with loading.

Power losses are expressed in kW or as a % of the loss at peak load.
Energy losses are expressed in kW-h per year or as a % of the total energy sold in a year.

Non-Technical Losses
Includes all unaccounted for energy other than technical losses. This can occur through theft, fraud, meter inaccuracies, and billing errors.

Unbilled Revenue
Revenue for energy consumed prior to the period end but not billed until the following period.

Loss Allocation
The process of dividing up the energy loss that occurs in a component amongst all the customers whose power flows through that component. This has traditionally been done in proportion to the energy sold to each user.

Load Factor
The number by which the peak load must be multiplied to obtain the average load. It can be calculated as (average load)/ (peak load) or by (the sum of the hourly loads expressed in per unit)/(number of hours).

Loss Factor
The number by which the power loss at peak load must be multiplied to obtain the average power loss. It can be calculated as (average loss)/(peak loss) or by (the sum of the square of the hourly loads expressed in per unit)/(number of hours).

Per Unit
A method of calculating based on expressing quantities as a fraction of the peak quantity. The per unit value is always between zero and 1 (inclusive).

Transformer Load Loss Parameter
The power loss of the transformer when carrying rated load divided by the power rating of the transformer. This can be obtained from the tendering documents when the transformer is purchased or, when these are not available, industry “typical” values can be used.

Transformer No-Load Loss Parameter
The power loss of the transformer when energized but carrying no load divided by the power rating of the transformer. This can be obtained from the tendering documents when the transformer is purchased or, when these are not available, industry “typical” values can be used.

1.2 Non-Technical Losses

Non-technical losses occur as a result of the difference between the amount of electricity distributed to customers and the amount that is actually paid for. These losses occur because of the following:

- Theft, fraud, meter tampering/bypassing
- Faulty meters - resulting in the amount of electricity used being under-recorded.
- Incorrect records, billing errors

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California “unaccounted for energy” is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales. (Ref 5).

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold (Ref 3) and the upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors (Ref 4).

Any distribution loss factor calculated from technical loss allocation must be increased to cover all forms of non-technical loss. In the past some Ontario utilities have used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 5% of energy sold this represents only 0.5% of energy sales as an estimate for non-technical losses. This is well below (<15%) of the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales. This figure has been adopted in this report.

1.3 Supply Facilities Factor

The supply facilities factor accounts for the energy losses that occur in the transmission station transformer, between the IESO settlement point and the meters on individual circuits leaving the station. Its main components are the load losses of the station transformer and the no-load losses of the station transformer. For circuits that are directly connected to a TS the factor has been set by the OEB as of May 2009 as 1.0045. For circuits that are supplied by a Hydro One express line the SFLF is 1.006.

2. METHODOLOGY

The basic methodology used to estimate the embedded distributor and site specific loss factors has been based on accepted loss estimation techniques within the utility industry (Ref 1).

This “normal” methodology is applicable to circuits in which the power flow on the various line segments increases and decreases together. This assumption allows the use of load factors and loss factors to calculate the average load and loss quantities from knowledge of the annual peaks. However, the power flow in circuits on which there is a significant amount of distributed generation do not all increase and decrease together. The presence of significant generation will mean that some line sections will have no power flow at all for some hours of the year. Which sections are experiencing no power flow will vary with the level of generation and the level of load on the circuit. A modified methodology was created to handle this situation, as described in section 2.2 of this report.

2.1 Normal Methodology

The normal method of estimating energy losses in distribution systems is to calculate the power loss under peak load conditions and then estimate the average power loss based on a loss factor. The average power loss can be multiplied by the number of hours in a year to obtain the annual energy loss. The distribution loss factor is calculated as the annual energy loss divided by the energy delivered.

A key step in this methodology is to calculate an accurate loss factor. This was achieved using the hourly interval data available from Haldimand County Hydro. The use of this accurate value of loss factor will produce the same result as calculating the energy loss in every hour of the year. The two methods are mathematically equivalent.

The normal method used for calculating site specific distribution loss factors is described in the following step sequence:

1 Obtain the interval load data for the circuit as a whole and the major loads.

2 Calculate the loss factor from the interval load data

3 Find the peak load for the year

4 Estimate the peak load on each line section and transformer in the path to the specific site for which a distribution loss factor is desired

5 Estimate the resistance of each line section (based on length and conductor size), and the transformer load loss and no-load loss parameters (based on industry averages)

6 Calculate the loss at peak load in each line section or transformer.
line power loss = I^2Rx3
transformer power loss = rating x load loss parameter x (peak load/rated load)^2 .

7 For each line section and transformer multiply the peak loss by the loss factor and the hours in a year to obtain the annual energy loss of that line section or transformer

8 For each transformer multiply the rating of the transformer by the transformer no-load loss parameter and by the number of hours in a year to obtain the annual energy lost to no-load losses on that transformer.

9 Allocate the annual energy loss on each line section or transformer to the customers whose power flows through that transformer in proportion to the energy used by the customers.

10 Total the allocated energy loss on all components used by a specific customer and divide by the energy sold to that customer to obtain the technical loss factor.

11 Add the non-technical losses to the technical loss factor and multiply by the supply facilities factor to obtain the total loss factor.

Step 4 involves estimating the way in which load divides up between different branches of a circuit. If all the loads are known this would be easy. However, the only interval load data that was available was for the major loads and the circuit as a whole. The load on the "rest of the circuit" was obtained by subtracting the known loads from the total circuit load. The "rest of circuit" load was divided up between the various branches of the circuit in proportion to the length of line downstream on that branch. This assumes an even load distribution for all the small loads.

The following assumptions are part of the normal methodology:

- conductor resistance is always the resistance at peak load
- the loss factor is the same throughout a circuit
- the "rest of the circuit" load is evenly distributed
- typical industry values for 27.6/8 kV transformer loss parameters (load loss 0.005, no-load loss 0.002)
- power factor of 0.95
- balanced currents in the three phase lines
- nominal voltage

The possible effects of these assumptions on the results is discussed in section 4 of this report.

2.2 Methodology for Circuits with Significant Generation

A modification of the normal methodology was required for circuit 31M2 on which there are significant amounts of distributed generation in the form of wind farms and a co-gen system. On this circuit the use of single loss factor for every line section was not valid because the load on a specific section could vary in different ways than the total circuit load because of the varying generation on the circuit. For this circuit the load on each line section was estimated for every hour of the year and the losses calculated separately for each hour and then summed. This eliminates steps 2 and 3 but expands steps 4-9 to be a different calculation for every hour of the year.

3. RESULTS OF CALCULATIONS

The calculations have been performed in spreadsheet files based on 2008 interval loading data supplied by Haldimand County Hydro. A single year of data was used as there is no averaging interval approved by the OEB for site specific losses.

3.1. Embedded Distributor Loss Factors

There was only one embedded distributor in 2008 (Norfolk Power) and it was supplied from two points on circuit 57M4. A site specific loss factor has been calculated for each of these supply points and is shown in the table below. The technical and non-technical losses are expressed as a fraction of the energy sold.

Table 1 Embedded Distributor DLF and TLF

Location	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor
6th Concession PMU	0.0232	0.0120	1.0352	1.0045	1.0399
Highway 6 PMU	0.0275	0.0120	1.0395	1.0045	1.0442

The 6th Concession PMU supply point has not been used since December 12, 2008. In 2009 the TLF for the embedded distributor should be 1.0442. After December 2010 the Highway 6 PMU supply point is planned to be removed from service.

3.2. Site Specific Loss Factors

A site specific loss factor has been calculated for each of the requested customer locations and is shown in the table below.

Table 2 Site Specific DLF and TLF

Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor
Canadian Gypsum Company	0.0235	0.012	1.0355	1.0060	1.0417
5th Line PMU	0.0085	0.012	1.0205	1.0060	1.0266
3rd Line PMU	0.0260	0.012	1.0380	1.0060	1.0442
4th Line PMU	0.0254	0.012	1.0374	1.0060	1.0436
6th Line PMU	0.0314	0.012	1.0434	1.0060	1.0497
Georgia Pacific	0.0090	0.012	1.0210	1.0060	1.0271
Green's Road PMU	0.0105	0.012	1.0225	1.0060	1.0286
Argyle PMU	0.0280	0.012	1.0400	1.0060	1.0462
Air Products	0.0047	0.012	1.0167	1.0045	1.0213
Springvale PMU	0.0379	0.012	1.0499	1.0060	1.0562
Wainfleet PMU	0.0178	0.012	1.0298	1.0060	1.0360

If a rate class combining the first nine sites is developed then the appropriate TLF for the rate class would be an average of all the nine sites weighted by the amount of energy sold at each site. This would allow correct recovery of losses from this group, assuming the loading on each circuit and each individual load remained similar from year to year. The calculation is shown in Table 3 below. The TLF for the group would be 1.0297.

Table 3 Calculation of Group 1 TLF

Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Canadian Gypsum Company	0.0235	0.012	1.0355	1.0060	1.0417	43685559	0.2904	0.3025
5th Line PMU	0.0085	0.012	1.0205	1.0060	1.0266	2686332	0.0179	0.0183
3rd Line PMU	0.0260	0.012	1.0380	1.0060	1.0442	9407734	0.0625	0.0653
4th Line PMU	0.0254	0.012	1.0374	1.0060	1.0436	2521158	0.0168	0.0175
6th Line PMU	0.0314	0.012	1.0434	1.0060	1.0497	2491772	0.0166	0.0174
Georgia Pacific	0.0090	0.012	1.0210	1.0060	1.0271	13971384	0.0929	0.0954
Green's Road PMU	0.0105	0.012	1.0225	1.0060	1.0286	4346460	0.0289	0.0297
Argyle PMU	0.0280	0.012	1.0400	1.0060	1.0462	1045806	0.0070	0.0073
Air Products	0.0047	0.012	1.0167	1.0045	1.0213	70264000	0.4671	0.4771
Sum						150420206		1.0305

The Fraction of Group Column is the Annual Energy divided by the sum of the annual energies.
The Contribution to the Weighted Average column is the Fraction of Group multiplied by the Total Loss Factor.

A similar calculation can be done for other groups, such as combining the loads at Wainfleet and Springvale into a rate class. The calculation is shown in Table 4 below.

Table 4 Calculation of Group 2 TLF

Customer	Technical Losses	Non-Technical Losses	Distribution Loss Factor	Supply Facilities Factor	Total Loss Factor	Annual Energy kWh	Fraction of Group	Contribution to Weighted Average TLF
Springvale PMU	0.0379	0.012	1.0499	1.0060	1.0562	35100000	0.56151	0.5931
Wainfleet PMU	0.0178	0.012	1.0298	1.0060	1.0360	27410000	0.43849	0.4543
Sum						62510000		1.0474

4. SENSITIVITY STUDY

The Distribution and Total Loss Factor values presented in section 3 are based on modeling of the technical energy losses on specific circuits. This modeling has inherent inaccuracies due to available data and the detail of the modeling that the available data allows. A study has been done to evaluate how sensitive are the calculated values for technical losses and TLF to uncertainty in the input data and the assumptions used in modeling.

The major sources of uncertainty in the values are shown in the following table. Not all of the sources apply to all of the site specific total loss factors. Not all sources of uncertainty will act in the same direction so the total uncertainty is somewhat less than a simple sum of all the factors. The cumulative effect of all the parameter sensitivities, some positive and some negative is expected to be about 10% in the technical losses and 20% in the TLF. This is a practical estimate of the probable range, not a "worst case".

Table 5 Summary of Estimation Uncertainty

Source	Uncertainty In Energy Losses(%)
Conductor Resistance	5%
Line Lengths	0.5%
Variation of loss factor within a circuit	2%
Assumption of even distribution for "rest of circuit" load	5%
Transformer Load Loss Parameter	0.5%
Transformer No-Load Loss Parameter	5%
Load Data	<1%
Power Factor	2%
Phase Current Unbalance on lines	<1%
Non-Technical Losses Assumption	12% (in TLF only)
Partial Year Data for Wind Farm	27%

Conductor Resistance

The resistance of the line conductors depends on the size of the conductor, the material from which it is made, the temperature and to a lesser extent the type of stranding and the strength of sunlight. Haldimand County Hydro provided good data on the size of the conductor and the material. The temperature of the conductor depends on the loading, the ambient temperature and the wind speed. Although the load is known on an hourly basis the ambient temperature and wind speed are not. The standard engineering practice (Ref 1) is to use the resistance of the conductor at 75°C (which occurs at rated load) and then adjust the resistance down based on the loading. This procedure still leaves significant uncertainty in the calculation because it adjusts the resistance to the value that would occur at peak load. At off peak conditions the resistance would be lower. The possible size of this uncertainty in conductor temperature on the calculated energy losses can be estimated from the following graph showing the effect of temperature on the resistance of the conductor material. Most of the HCHI line sections in this study are loaded at less than 50% of rating at peak, putting the resistance at peak in the middle of the graph. Since conductor temperatures below zero are unlikely at load levels

that would result in a significant loss, the maximum uncertainty in the resistance is about 10% (0.85-0.75). The actual uncertainty would be less than this maximum. A value of 5% would be a reasonable estimation. This means that the conductor resistance modeling causes an uncertainty of about 5% in the energy loss estimates.

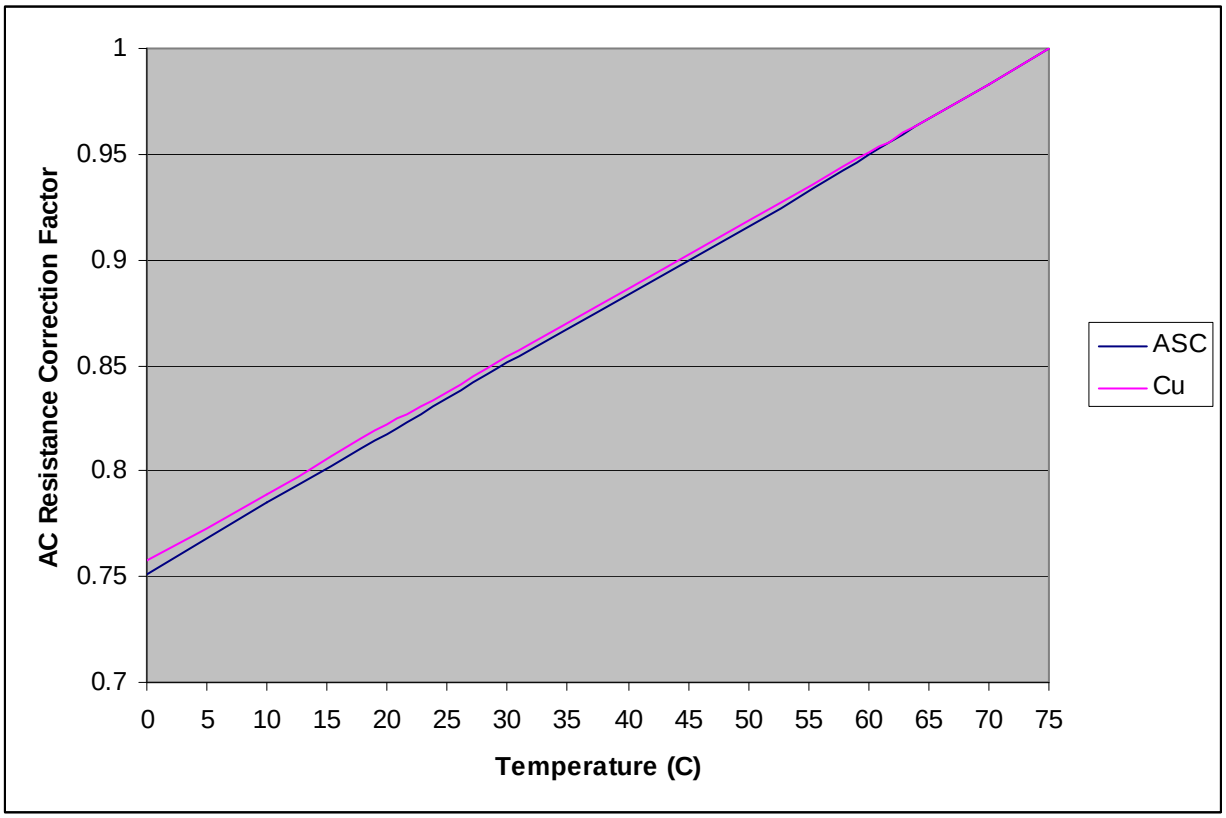

Figure 1 Effect of Temperature on Conductor Resistance

Line Lengths

The line lengths were provided by HCHI to a precision of ±5 metres. Since most line sections in the model that have a significant contribution to the energy losses are longer than 1 km, this source of uncertainty is less than 0.5% of the energy loss values. It is therefore insignificant compared to other sources of uncertainty.

Variation of Loss Factor within a Circuit

The modeling applied a single loss factor to all line sections in a circuit. This loss factor was calculated from the interval load data for the circuit as a whole. This is accurate for the line sections closest to the source. However, if the load profiles of the individual loads were significantly different, then the line section directly upstream of each load might have a significantly different loss factor. The possible effect of this was investigated by comparing the loss factors at the circuit level to the loss factors of the known loads. In all cases the loss factors were within a 2-20% range. The 20% figure sounds high but it would apply only if there was only the one load on the line section. When this occurs the loss on that section is usually a small fraction of the total energy loss on the circuit and the overall loss estimate

would be affected much less than 20%. A reasonable estimate for the uncertainty in the overall loss estimate due to loss factor variations for end of the line sections is ±2%.

Assumption of Even Distribution for "Rest of Circuit" Load

The "rest of the circuit" load consists of all the small loads for which location and load data were not available. On average this comprised 40% of the load on the circuit. How this load is distributed on the circuit can have a significant effect on energy losses. However, for the lines close to the station, how the load is distributed has no effect since all the load flows through these lines in any distribution. On the other lines the maximum effect would be a 40% change in load, but a 5% variation of total load from evenly distributed would be a more reasonable "maximum". Estimating half the lines affected by a 5% change in load creates a change in the total energy losses of about 5%.

Transformer Loss Parameters

Some of the site specific loss factors were calculated for locations on 8 kV lines. These locations were 3rd Line PMU, 4th Line PMU, 6th Line PMU, and Argyle PMU. The 8 kV lines are supplied through a 27.6/8 kV transformer. The losses in these transformers were estimated based on a "typical" value for transformer loss parameters (Ref 1) since no data on the specific transformers (Lythmore DS and Argyle DS) was available. The possible range of transformer loss parameters is quite large because transformers are individually designed to meet the cost requirements of the utility purchasing the unit. A range of ±10% is possible. This would only affect the energy lost in the transformer which was between 40% and 60% of the energy loss allocated to these locations. A change of 10% in the transformer parameter would change the Distribution Loss Factor estimated for these locations by 4% to 6%. About 90% of the transformer loss was no-load loss.

Load Data

Although the interval data provided is very accurate (about +/- 0.05%) it is averaged over an hour long interval. During this interval the actual loading will be some what higher or lower. The losses calculated using a long interval are usually less than the losses that would be calculated using a shorter interval. If minute interval data were available they would show a higher than average loss at some times and a lower than average loss at others, but because of the losses are proportional to the square of the loading the losses do not average out to the loss value calculated at the average load. The increased losses at times of slightly higher load are greater than the decreased losses at times of slightly lower load. The size of this effect depends on the variability of the loading. Figure 2 shows the possible size of the effect. In the graph the load was varied around an average of 0.5 for several different ranges of variation, i.e. in a 0.5 range the actual load values varied from 0.25 to 0.75.

The amount of variation around the hourly average that can be expected varies with the location within the power system. The farther up the system the load is being studied the lower the range of variation will be around the average. At the 27.6 kV circuit level a variation of +/- 20% might be expected (range of 0.1 on the graph) giving a negligible change in the losses. However, near the end of an 8 kV circuit the variation might be +/- 30% on a minute by minute basis and this would result in a change of loss of 2.4%. However, the loss on the farther out sections of the circuit is generally much less than the loss closer to the transformer station and so the actual effect might be even less. The conclusion is that the hourly interval load could be having only a small effect (<1% of the loss value) on the calculated energy losses.

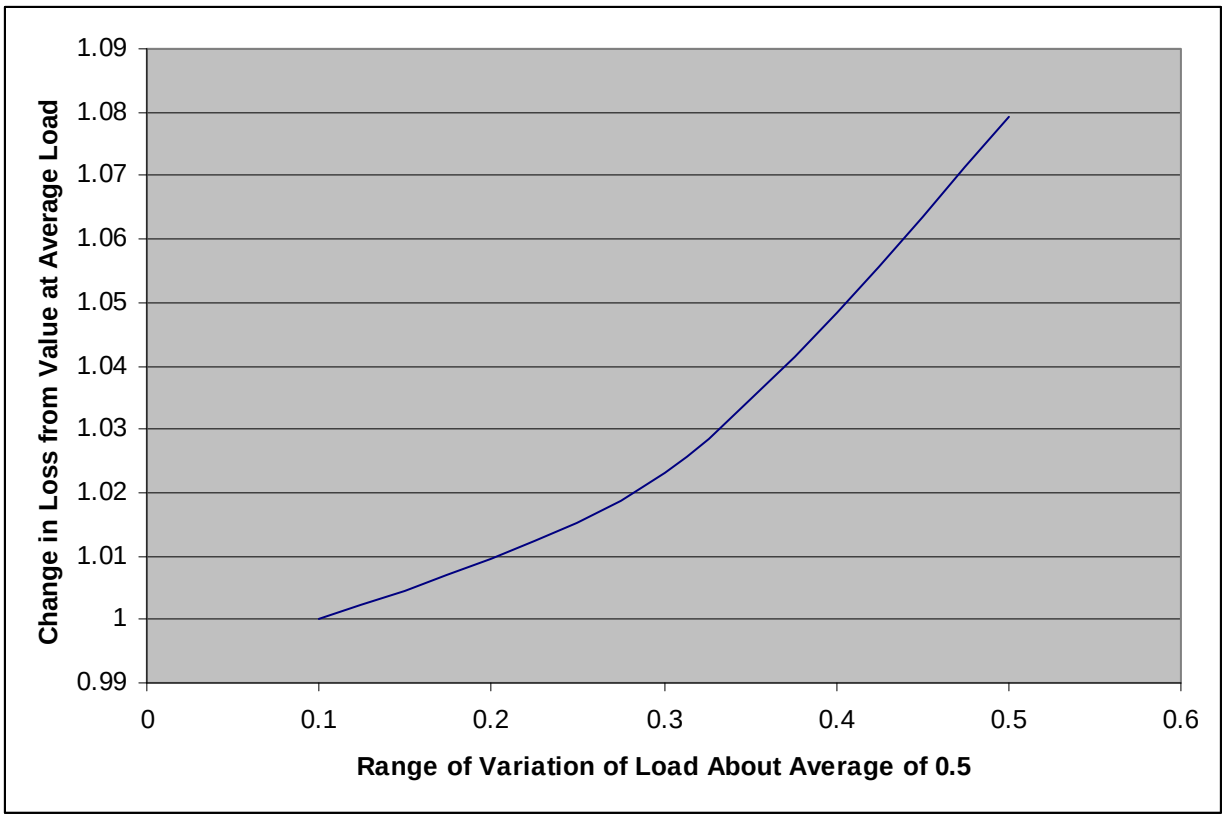

Figure 2 Effect of Hourly Average Interval Load Data on Calculated Losses

Power Factor

The loading in the model was based on interval energy data. When converting this load data into current in the line it was assumed that the power factor was 0.95. This is a typical power factor in utility lines but it could be as low as 0.9 or as high as 0.99. This creates an uncertainty in the load currents of ±5% and a corresponding uncertainty in the energy loss estimate of ±10%. This is a "worst case" estimate and the actual uncertainty is likely closer to 2%.

Phase Current Unbalance on Lines

The loading in the model was based on interval energy data. When converting this load data into current in the line it was assumed that the currents in each of the three phases were equal. This will be a good assumption for line sections close to the station and it will become less valid moving away from the transformer station to sections that are farther away. The major loads will be well balanced between phases because they are three phase loads, but the "rest of circuit" load (about 40% of the total) will generally be single phase loads which are impossible to balance completely. Generally the single phase loads can be balanced with at best a 20% imbalance. A 20% imbalance leads to an increase in energy losses of about 6% mainly due to current flow in the neutral and ground. Since this only affects 40% of the load in this study and then only on about half the lines, the overall uncertainty in energy losses is estimated as 1%. This is a maximum value based on the single phase loads being 20% unbalanced. If the unbalance is less than 10% the increase in energy loss becomes negligible.

Non-Technical Losses Assumption

The non-technical losses included in the Total Loss Factor are very difficult to estimate accurately. Published figures are scarce and may not apply to an individual utility because the variation is expected to be large. The value of 1.2% of energy sold is an estimate based on available data.

In the past experience of Kinectrics some utilities have used a value of 10% of the technical losses, which in this study would range from 0.5% to 0.09% because of the site specific loss calculation. The 0.5% would be at the very low end of the range of published figures for non-technical losses. This suggests that uncertainty in the non-technical losses creates an uncertainty of 12% in the TLF values in this report.

Partial Year Data for Wind Farm

On circuit 31M2 the 10 MW Mohawk Point wind farm was only on line for about 75 days in 2008. The DLF and TLF calculated for Wainfleet PMU are therefore based on 10 months without the wind generation and 2 months with it. When the wind farm is operational the technical loss allocated to Wainfleet PMU is expected to be reduced from 0.0178 to 0.013 a reduction of 27% in the energy loss. The lower value may be more representative of data in future years.

5.0 CONCLUSIONS AND RECOMMENDATIONS

1 The recommended embedded distributor DLF for Norfolk Power is 1.0395 and the TLF is 1.0442. This estimate includes 1.2% for non-technical losses and a supply facilities factor of 1.0045. It is based on the Highway 6 PMU location only because the 6th Line location was removed from service December 12, 2008. The Highway 6 location is planned to be removed in December 2010.

2 The recommended site specific DLFs and TLFs are shown in the following table:

Customer	Distribution Loss Factor (DLF)	Total Loss Factor (TLF)
Canadian Gypsum Company	1.0355	1.0417
5th Line PMU	1.0205	1.0266
3rd Line PMU	1.0380	1.0442
4th Line PMU	1.0374	1.0436
6th Line PMU	1.0434	1.0497
Georgia Pacific	1.0210	1.0271
Green's Road PMU	1.0225	1.0286
Argyle PMU	1.0400	1.0462
Air Products	1.0167	1.0213
Springvale PMU	1.0499	1.0562
Wainfleet PMU	1.0298	1.0360

These values include 1.2% for non-technical losses and a supply facilities factor of 1.006 or 1.0045 as appropriate.

3 If a group rate is established for the first nine load locations, the appropriate TLF is an average of the site specific TLFs weighted by the annual energy sold at each site. Based on the 2008 data and with an assumed 8 MW load for Air Products, this value is 1.0305

If a group rate is established for the last two sites the appropriate TLF, based on 2008 data, is 1.0474

4 The results of this study have an inherent uncertainty due to the modeling used to calculate them. The uncertainty in the technical loss estimates has been estimated to be ±10% and in the TLFs ±20%.

5 The DLF and TLF for the Wainfleet PMU should be recalculated when a full year of data is available with the Mohawk Point wind farm in service. The site specific DLF and TLF could drop by 27% of the value estimated in this report.

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Appendix A Calculation Details

The red numbers in the single line diagrams identify the line section numbers in the circuit calculation tables.

Figure 3 27M3 Single Line Diagram

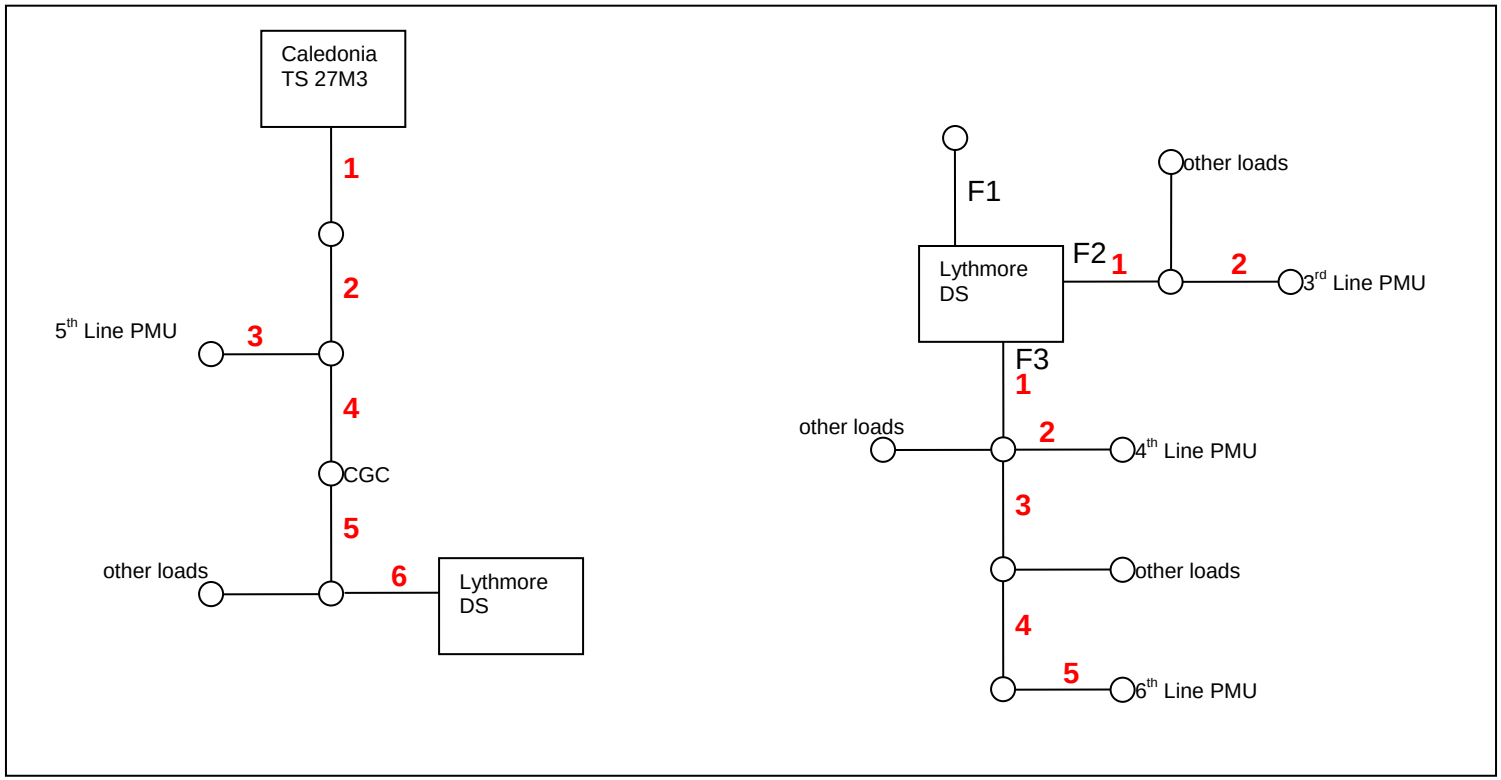

Table 6 27M3 Line Section Calculations

Section	1	2	3	4	5	6
Line Length (km)	0.36	2.16	0.24	4.15	0.51	0.80
Conductor Size	1000	336	3/0	336	336	336
Conductor Resistance (ohms/km)	0.09	0.21	0.42	0.21	0.21	0.21
Conductor Current Rating (amps)	990	495	310	495	495	495
Section Resistance (ohms)	0.03	0.45	0.08	0.85	0.09	0.13
Fraction of Circuit Total Load	1.00	1.00	0.03	0.97	0.57	0.13
Peak Current (amps per phase)	485.08	485.08	12.61	472.47	276.50	62.58
Peak Loss (kW)	19.07	315.56	0.04	571.49	21.64	1.53
Loss Factor	0.30	0.30	0.30	0.30	0.30	0.30
Annual Loss (kWh)	49777	823765	95	1491854	56502	3988

The conductor resistance (ohms/km) in the table is the resistance when the conductor is loaded to its rating. The section resistance (ohms) is the product of the line length and the conductor resistance adjusted for the actual loading of the section.
Section Resistance = line length x conductor resistance x (0.75 + 0.25 x (peak current/rated current))
This assumes that the resistance at very low load is 75% of the resistance at rated load and that resistance varies linearly with loading. This assumption is discussed in report Section 4 on page 10.

The annual loss on each section is the product of the loss at peak, the loss factor and the hours in a year
Annual Loss = peak loss x loss factor x 8784

Table 7 27M3 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Load Fraction Section 1	Load Fraction Section 2	Load Fraction Section 3	Load Fraction Section 4	Load Fraction Section 5	Load Fraction Section 6	Allocated Loss (kWh)	Technical Loss (fraction of energy sold)
CGC	42.70%	43685559	0.4270	0.4270	0.0000	0.4384	0.0000	0.0000	1027029	0.0235
5th line PMU	2.60%	2686331.9	0.0260	0.0260	1.0000	0.0000	0.0000	0.0000	22807	0.0085
Lythmore DS	12.60%	12900000	0.1260	0.1260	0.0000	0.1294	0.2211	0.9767	319443	0.0248

The “Load Fraction Section 1” is the fraction of the load on section 1 that is due to the load point of the row.

The “Allocated Loss” to each load point is the product of the load fraction for each section and the annual loss on that section (from the bottom row of the previous table) summed over all sections. For example for the load point CGC, the Allocated Loss of 1027029 kWh = 0.4270*49777 + 0.4270*823765 + 0.4384*1491854. (The hand calculation is not exact because of the round off error working to 4 decimal places).

Table 8 Lythmore F2 Line Section Calculations

Section	1	2
Line Length (km)	0.45	1.00
Conductor Size	3/0	3/0
Conductor Resistance (ohms/km)	0.416	0.416
Conductor Current Rating (amps)	310	310
Section Resistance (ohms)	0.15	0.32
Fraction of Circuit Total Load	1.00	0.54
Peak Current (amps per phase)	45.06	24.33
Peak Loss (kW)	0.90	0.57
Loss Factor	0.18	0.18
Annual Loss (kWh)	1375	872

Table 9 Lythmore Station Transformer Calculations

	DS Load Loss	DS No Load Loss
Transformer Size (KVA)	5000	5000
Loss Parameter	0.005	0.002
Peak Load Fraction of Rating	0.20	
Peak loss (kW)	8.61	10.00
Loss Factor	0.18	1.00
Annual Loss (kWh)	13206	87600

Table 10 Lythmore F2 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Load Fraction Section 1	Load Fraction Section 2	Load Fraction DS Transformer	Allocated Loss (kWh)	Technical Loss on DS and 8 kV Line(fraction of energy sold)	Technical Loss on 27.6 kV Line (fraction of energy sold)	Total Technical Loss (fraction of energy sold)
3rd Line PMU	49.00%	9407734.1	0.4900	0.9074	0.0980	11344	0.0012	0.0248	0.0260

The allocated loss for a load point on an 8 kV line includes the loss from the 8 kV line allocated to that load point, plus the substation transformer loss allocated to that load point. This is expressed as a % of energy sold to the load point (Technical Loss on DS and 8 kV Line) and added to the technical loss on the 27.6 kV line that was allocated to the substation to produce the total technical loss for the load point.

Table 11 Lythmore F3 Line Section Calculations

Section	1	2	3	4	5
Line Length (km)	2.41	1.26	2.13	2.13	1.57
Conductor Size	3/0	3/0	3/0	3/0	#2
Conductor Resistance (ohms/km)	0.416	0.416	0.416	0.416	1.05
Conductor Current Rating (amps)	310	310	310	310	184
Section Resistance (ohms)	0.80	0.39	0.69	0.68	1.28
Fraction of Circuit Total Load	1.00	0.07	0.61	0.38	0.32
Peak Current (amps per phase)	60.83	4.38	36.99	23.06	19.47
Peak Loss (kW)	8.89	0.02	2.84	1.09	1.46
Loss Factor	0.18	0.18	0.18	0.18	0.18
Annual Loss (kWh)	13635	35	4347	1665	2231

Table 12 Lythmore F3 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Load Fraction Section 1	Load Fraction Section 2	Load Fraction Section 3	Load Fraction Section 4	Load Fraction Section 5	Load Fraction DS Transformer	Allocated Loss (kWh)	Tech. Loss on DS and 8 kV Line	Tech. Loss on 27.6 kV Line	Total Technical Loss
4th Line PMU	4.00%	2521158.4	0.04	1.00	0.00	0.00	0.00	0.011	1027029	0.0007	0.0248	0.0254
6th Line PMU	28.00%	2491772.4	0.28	0.00	0.46	0.74	0.88	0.076	22807	0.0067	0.0248	0.0314

Figure 4 27M6 Single Line Diagram

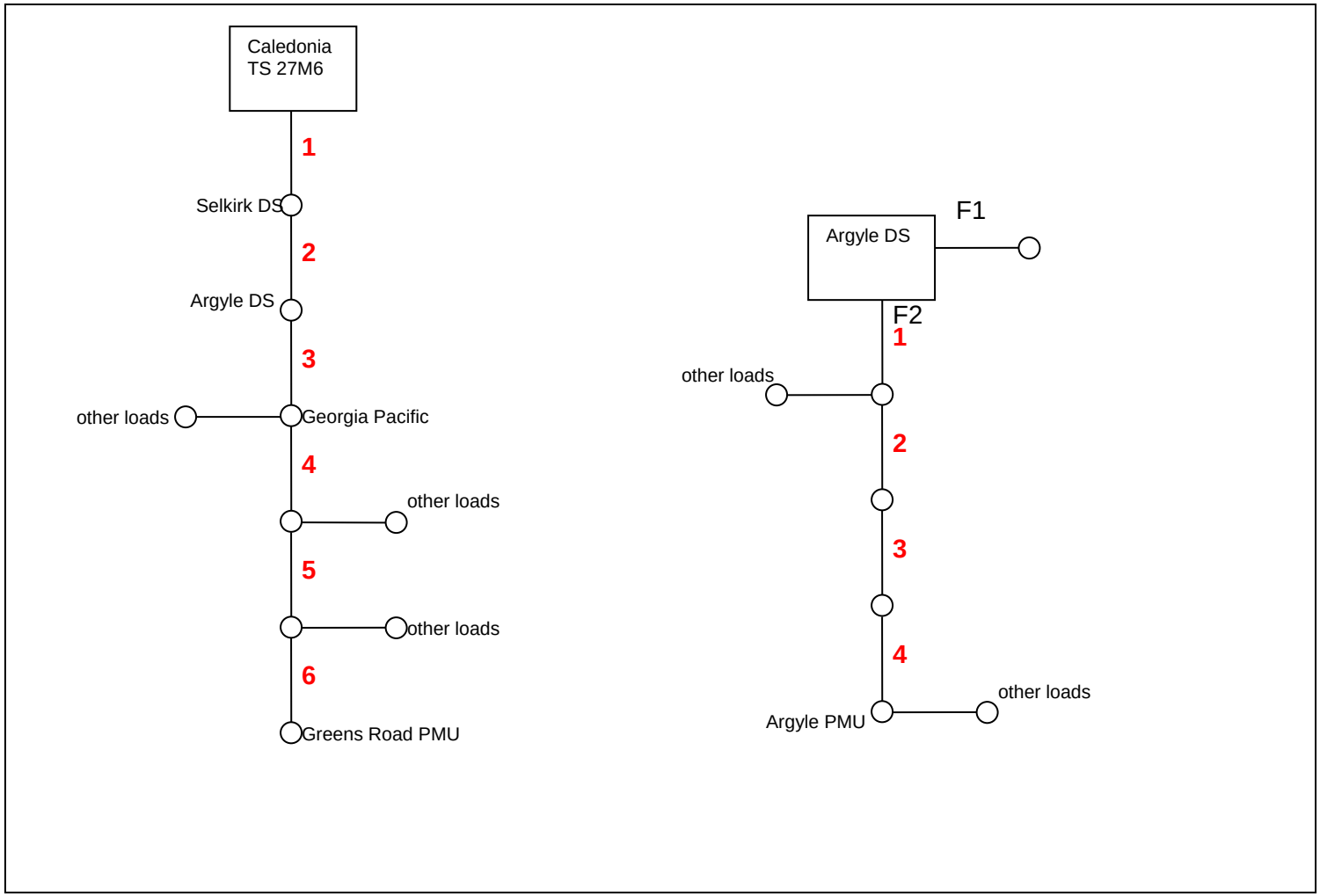

Table 13 27M6 Line Section Calculations

Section	1	2	3	4	5	6
Line Length (km)	2.73	1.41	0.41	2.5	1.26	0.8
Conductor Size	336	336	336	336	336	3/0
Conductor Resistance (ohms/km)	0.208	0.208	0.208	0.208	0.208	0.416
Conductor Current Rating (amps)	495	495	495	495	495	310
Section Resistance (ohms)	0.52	0.26	0.07	0.41	0.20	0.26
Fraction of Circuit Total Load	1.00	0.81	0.62	0.22	0.12	0.08
Peak Current (amps per phase)	324.87	262.49	202.07	71.47	38.01	25.01
Peak Loss (kW)	164.34	53.51	8.90	6.26	0.87	0.48
Loss Factor	0.27	0.27	0.27	0.27	0.27	0.27
Annual Loss (kWh)	388701	126550	21052	14816	2067	1138

Table 14 27M6 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Load Fraction Section 1	Load Fraction Section 2	Load Fraction Section 3	Load Fraction Section 4	Load Fraction Section 5	Load Fraction Section 6	Allocated Loss (kWh)	Technical Loss (fraction of energy sold)
Selkirk DS	19.20%	12400000	0.19	0.00	0.00	0.00	0.00	0.00	74631	0.0060
Argyle DS	18.60%	12000000	0.19	0.23	0.00	0.00	0.00	0.00	101430	0.0085
Georgia Pacific	21.60%	13971384	0.22	0.27	0.35	0.00	0.00	0.00	125101	0.0090
Greens Rd PME	6.70%	4346460	0.0670	0.0829	0.1077	0.3045	0.5726	0.8701	45490	0.0105

Table 15 Argyle F2 Line Section Calculations

Section	1	2	3	4
Line Length (km)	1.08	1.08	2.03	1.18
Conductor Size	3/0	3/0	#2	3/0
Conductor Resistance (ohms/km)	0.416	0.416	1.05	0.416
Conductor Current Rating (amps)	310	310	185	310
Section Resistance (ohms)	0.36	0.35	1.72	0.38
Fraction of Circuit Total Load	1.00	0.68	0.63	0.55
Peak Current (amps per phase)	65.73	44.69	41.41	36.15
Peak Loss (kW)	4.68	2.12	8.84	1.50
Loss Factor	0.19	0.19	0.19	0.19
Annual Loss (kWh)	7618	3448	14398	2443

Table 16 Argyle DS Transformer Calculations

	DS Load Loss	DS No Load Loss
Transformer Size (KVA)	5000	5000
Loss Parameter	0.005	0.002
Peak Load Fraction of Rating	0.37	
Peak loss (kW)	5.35	10
Loss Factor	0.186	1
Annual Loss (kWh)	8725	87600

Table 17 Argyle F2 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Load Fraction Section 1	Load Fraction Section 2	Load Fraction Section 3	Load Fraction Section 4	Load Fraction DS Transformer	Allocated Loss (kWh)	Technical Loss on DS and 8 kV Line(fraction of energy sold)	Technical Loss on 27.6 kV Line (fraction of energy sold)	Total Technical Loss (fraction of energy sold)
Argyle PMU	27.00%	1045806	0.27	0.40	0.43	0.49	0.10	20419	0.0195	0.0085	0.0280

Figure 5 57M1 Single Line Diagram

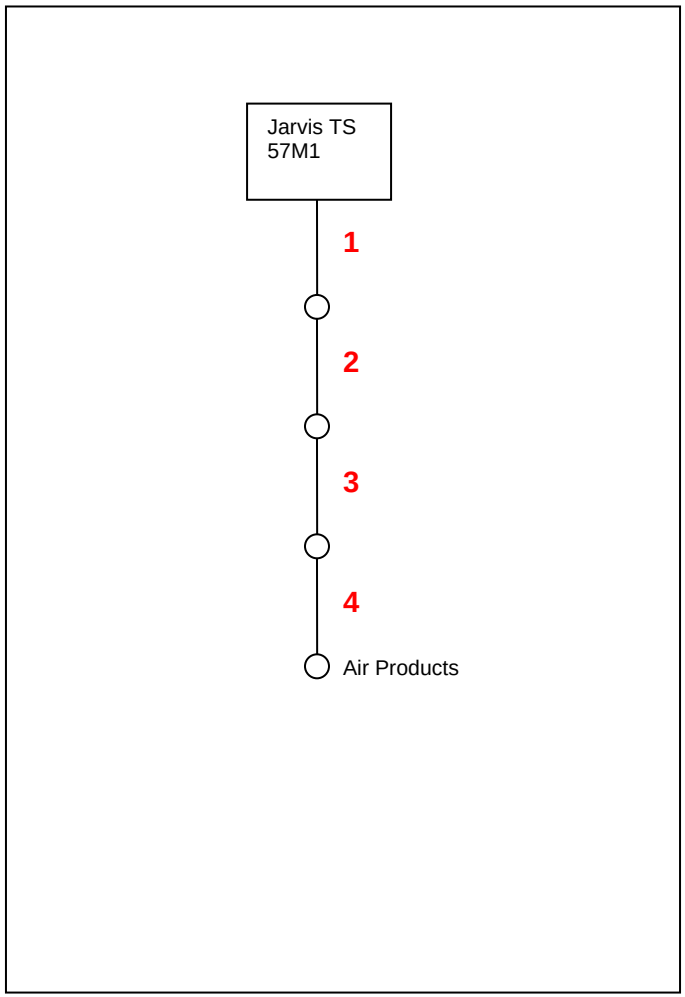

Table 18 27M6 Line Section Calculations

Section	1	2	3	4
Line Length (km)	1.5	2.35	1	0.3
Conductor Size	795	795	795	795
Conductor Resistance (ohms/km)	0.086	0.086	0.086	0.086
Conductor Current Rating (amps)	855	855	855	855
Section Resistance (ohms)	0.11	0.17	0.07	0.02
Fraction of Circuit Total Load	1.00	0.99	0.99	0.96
Peak Current (amps per phase)	245.32	241.64	241.64	236.49
Peak Loss (kW)	19.14	29.05	12.36	3.55
Loss Factor	0.65	0.65	0.65	0.65
Annual Loss (kWh)	108640	164919	70178	20128

Table 19 27M6 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Load Fraction Section 1	Load Fraction Section 2	Load Fraction Section 3	Load Fraction Section 4	Allocated Loss (kWh)	Technical Loss (fraction of energy sold)
Air Products	90.20%	70264000	0.90	0.92	0.92	0.94	332114	0.00473

Figure 6 57M3 Single Line Diagram

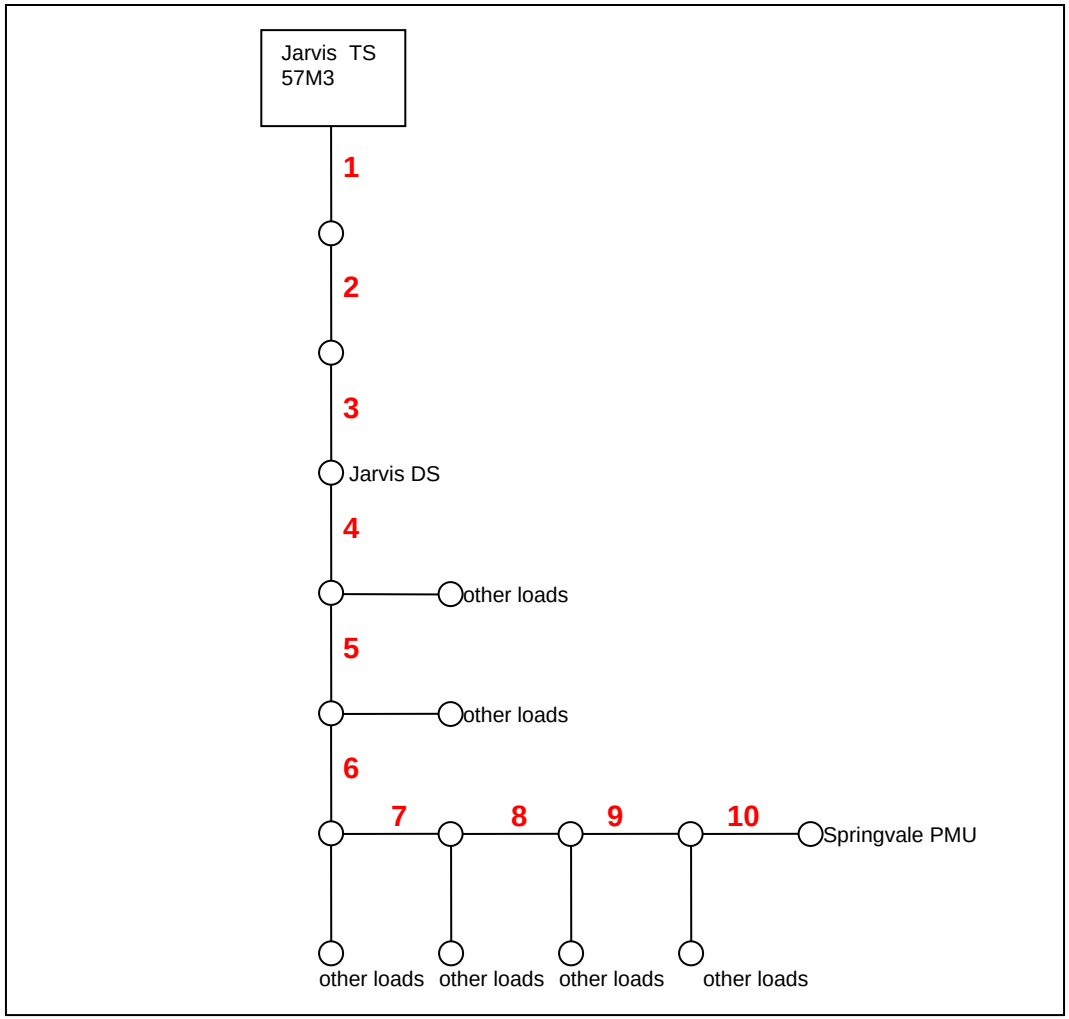

Table 20 57M3 Line Section Calculations

Section	1	2	3	4	5	6	7	8	9	10
Line Length (km)	2.9	0.65	5	3	1.5	1.5	1.5	1.5	1.5	0.6
Conductor Size	795	336	3/0	3\0	3/0	3/0	3/0	3/0	3/0	3/0
Conductor Resistance (ohms/km)	0.086	0.208	0.416	0.416	0.416	0.416	0.416	0.416	0.416	0.416
Conductor Current Rating (amps)	855	495	310	310	310	310	310	310	310	310
Section Resistance (ohms)	0.20	0.12	1.94	1.12	0.56	0.55	0.55	0.55	0.55	0.22
Fraction of Circuit Total Load	1.00	1.00	1.00	0.81	0.76	0.74	0.71	0.70	0.68	0.66
Peak Current (amps per phase)	228.63	228.63	228.63	185.19	174.33	168.62	162.33	160.96	154.67	150.67
Peak Loss (kW)	31.95	18.35	304.78	115.48	50.67	47.16	43.45	42.67	39.17	14.81
Loss Factor	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
Annual Loss (kWh)	103269	59314	985180	373286	163784	152427	140463	137925	126626	47887

Table 21 57M3 Load Point Calculations

			Load Fraction on Section											
Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	1	2	3	4	5	6	7	8	9	10	Allocated Loss (kWh)	Technical Loss (fraction of energy sold)
Springvale PMU	65.60%	35100000	0.66	0.66	0.66	0.81	0.86	0.89	0.92	0.93	0.97	1.00	1331738	0.0379

Figure 7 57M4 Single Line Diagram

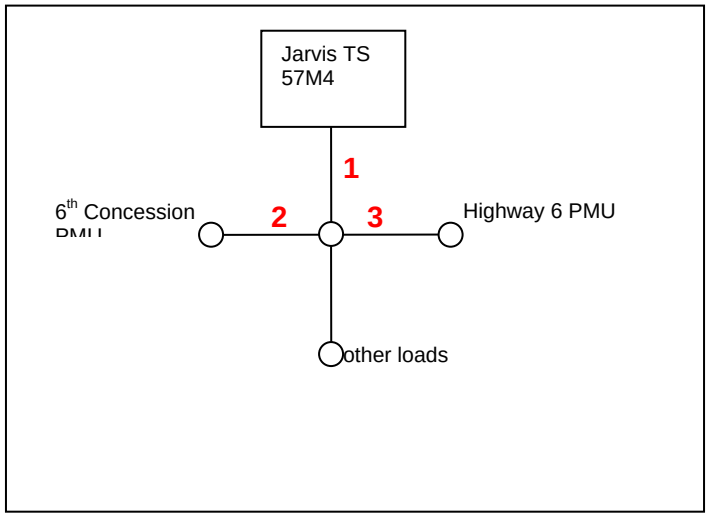

Table 22 57M4 Line Section Calculations

Section	1	2	3
Line Length (km)	8	2.2	3.5
Conductor Size	336	336	336
Conductor Resistance (ohms/km)	0.208	0.208	0.208
Conductor Current Rating (amps)	495	495	495
Section Resistance (ohms)	1.56	0.36	0.62
Fraction of Circuit Total Load	1.00	0.16	0.58
Peak Current (amps per phase)	371.60	57.60	213.67
Peak Loss (kW)	646.36	3.55	85.54
Loss Factor	0.32	0.32	0.32
Annual Loss (kWh)	1828857	10039	242038

Table 23 57M4 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Load Fraction Section 1	Load Fraction Section 2	Load Fraction Section 3	Allocated Loss (kWh)	Technical Loss (fraction of energy sold)
6th Conc PMU	15.50%	12660000	0.16	1.00	0.00	293512	0.0232
Highway 6 PMU	57.50%	47100000	0.58	0.00	1.00	1293631	0.0275

Figure 8 31M2 Single Line Diagram

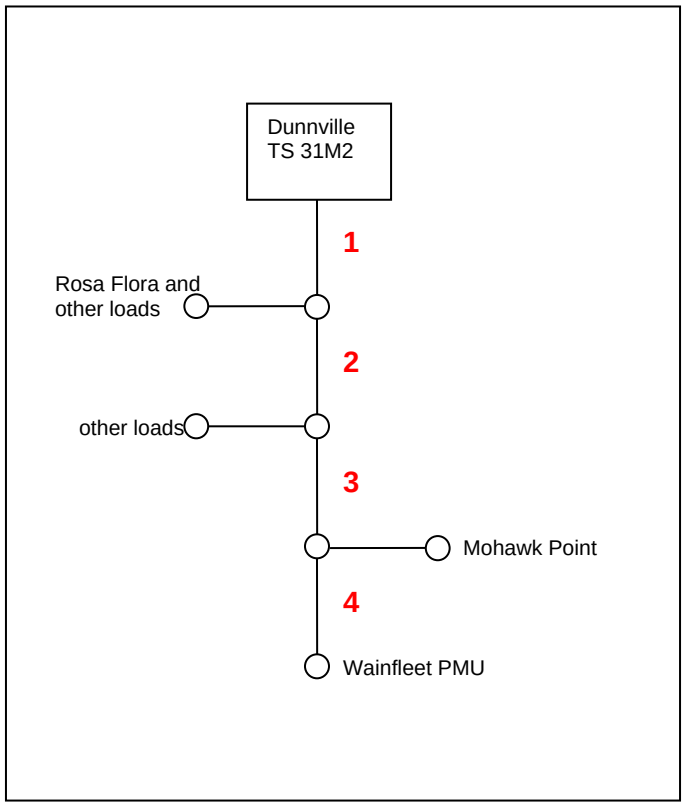

Table 24 31M2 Line Section Calculations

Section	1	2	3	4
Line Length (km)	1.3	2.42	1.5	5.22
Conductor Size	336	336	3/0	3\0
Conductor Resistance (ohms/km)	0.208	0.208	0.416	0.416
Conductor Current Rating (amps)	495	495	310	310
Section Resistance (ohms)	0.270	0.503	0.624	2.172
Peak Current (amps per phase)	296	251	123	123
Peak Loss (kW)	63.94	83.75	34.54	83.62
Annual Loss (kWh)	159179	226692	73525	248483

Table 25 31M2 Load Point Calculations

Load Point	Load (% of circuit total)	Annual Energy Sold (kWh)	Allocated Loss (kWh)	Technical Loss (fraction of energy sold)
Wainfleet PMU	45.30%	27410000	488433	0.0178

Note: These tables are different than the tables for other circuits because the calculation procedure for circuit 31M2 was different than for the other circuits, as described in the body of the report. These difference means that some of the cells in the other tables are not applicable to this circuit. For example the loss factor is not used at all, and the load fraction on each section is different for every hour of the year so a single number cannot be reported.

DISTRIBUTION

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Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2008-0181

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Haldimand County Hydro Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

Introduction

Haldimand County Hydro Inc. ("Haldimand County Hydro") is a licensed distributor of electricity providing service to consumers within its licensed service area. Haldimand County Hydro filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2009.

Haldimand County Hydro is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, Haldimand County Hydro is one of the electricity distributors to have its rates adjusted for 2009 on the basis of the 2nd Generation Incentive Rate Mechanism ("IRM")

process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2009 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process.

Notice of Haldimand County Hydro's rate application was given through newspaper publication in Haldimand County Hydro's service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. There were no intervention requests and no comments were received. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Haldimand County Hydro's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for Haldimand County Hydro, the Board has applied the policies described in the Report.

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2008 data published by Statistics Canada, the Board has established the price escalator to be 2.3%. The resulting price cap index adjustment is therefore 1.3%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. A change in the federal income tax rate effective January 1, 2009 was incorporated into the rate model and reflected in distribution rates.

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic Outlook and Fiscal Review (the "Fiscal Review"). The enabling legislation received Royal Assent on May 14, 2008. Included in this Fiscal Review were changes to the Ontario capital tax provisions[1], and an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2007.

The Federal Budget enacted on February 3, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009, and a change in the capital cost allowance (CCA) applicable to certain computer equipment and related system software (CCA class 50) acquired between January 27, 2009 and February 2011.

The Board has considered these fiscal changes and determined that the rate model will be adjusted to reflect the increase in the provincial and federal small business income limit for affected distributors, and the changes in the Ontario capital tax provisions. The Board is of the view that these changes when combined could be material, and should be passed through to ratepayers. With regard to the change in the CCA, the Board notes that this change would be captured in the revenue requirement calculation as it relates to smart meters when a distributor applies for cost recovery for the applicable investment period. For other computer equipment and related system software in class 50, the Board concludes that this adjustment is not required since it does not appear to be material.

The price cap index adjustment does not apply to the following components of distribution rates:

- Rate Riders;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Retail Service Charges;

[1] The Ontario capital tax rate decreased from 0.285% to 0.225% effective January 1, 2007. The Ontario capital tax deduction also increased from $10 million to $12.5 million effective January 1, 2007, and from $12.5 million to $15 million effective January 1, 2008.

- Loss Factors; and
- Smart Meter Funding Adder.

Rural or Remote Electricity Rate Protection Adjustment

In accordance with Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection ("RRRP") (made under the *Ontario Energy Board Act, 1998*) the Board issued a Decision on December 17, 2008 setting out the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

In a letter dated December 17, 2008 the Board directed distributors that had a rate application before the Board to file a request with the Board that the RRRP charge in their tariff sheet be revised to 0.13 cent per kilowatt-hour effective May 1, 2009.

Haldimand County Hydro complied with this directive. The rate model was adjusted to reflect the new RRRP charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law.

Haldimand County Hydro reports that it is authorized to conduct smart meter activities because it has procured smart meters pursuant to and in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc.

Haldimand County Hydro requested the standard smart meter funding adder of $1.00 per metered customer per month, which is intended to provide funding in the case where a distributor may be in the early stages of planning and may not yet have

sufficient cost information to request a utility-specific funding adder. The Board approves the funding adder of $1.00 per metered customer per month as proposed by Haldimand County Hydro. This new funding adder is reflected in the Tariff of Rates and Charges that is appended to this Decision and Order. Haldimand County Hydro's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.00 per metered customer per month is intended to provide funding for Haldimand County Hydro's smart metering activities in the 2009 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Haldimand County Hydro applies for the recovery of these costs.

Retail Transmission Service Rates

On October 22, 2008 the Board issued a Guideline for *Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") which provides electricity distributors with instructions on the evidence needed, and the process to be used, to adjust Retail Transmission Service Rates ("RTSRs") to reflect changes in the Ontario Uniform Transmission Rates ("UTRs").

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new UTRs for Ontario transmitters, effective January 1, 2009. The Board approved an increase of 11.3% to the wholesale transmission network rate, an increase of 18.6% to the wholesale transmission line connection rate, and an increase of 0.6% to the wholesale transformation connection rate. The combined change in the wholesale transmission and transformation connection rates is an increase of about 5%.

Electricity distributors are charged the UTRs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into

one retail connection service charge. Deferral accounts are also used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e., deferral accounts 1584 and 1586).

In the RTSR Guideline the Board directed all electricity distributors to propose an adjustment to their RTSRs to reflect the new UTRs for Ontario transmitters effective January 1, 2009. The objective of resetting the rates was to minimize the prospective balances in deferral accounts 1584 and 1586.

Haldimand County Hydro proposed to increase its RTSR – Network Service Rates by 11.3 % and to increase its RTSR – Line and Transformation Connection Service Rates by 5.5%. The Board finds that this approach is reasonable and therefore approves these adjustments.

The Board is providing Haldimand County Hydro with a rate model (spreadsheet) and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2008 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

Haldimand County Hydro's new distribution rates will be effective May 1, 2009. The Board orders that:

1. Haldimand County Hydro shall review the draft Tariff of Rates and Charges set out in Appendix A. Haldimand County Hydro shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information, within seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by Haldimand County Hydro to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

2. The draft Tariff of Rates and Charges set out in Appendix A of this Order will become final, effective May 1, 2009, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2009.

3. The Tariff of Rates and Charges set out in Appendix A of this Order shall supersede all previous distribution rate schedules approved by the Board for Haldimand County Hydro and is final in all respects.

4. Haldimand County Hydro shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

If the Board receives a submission by Haldimand County Hydro to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of Haldimand County Hydro and will issue a final Tariff of Rates and Charges.

DATED at Toronto, March 11, 2009

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix “A”

To Decision and Order

EB-2008-0181

March 11, 2009

Haldimand County Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0181

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Urban Density
Urban Density is an area containing 100 or more customers with a line density of at least 15 customers per kilometre.

Suburban Density
Suburban Density is an area that is not Urban Density.

Residential
This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. Residential includes Urban, Suburban and Farm customer's premises which can be occupied on a year-round and seasonal basis. Farm applies to properties actively engaged in agricultural production as defined by Statistics Canada. These premises must be supplied from a single phase primary line. The farm definition does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm.

General Service
General Service does include farms supplied from polyphase primary lines. General Service includes commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property.

General Service Less Than 50 kW
This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. 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
General Service greater than 1,000 to 5,000 kW interval metered.

Haldimand County Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0181

Unmetered Scattered Load
This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum 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, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting
This classification refers to an account that is an unmetered lighting load supplied to a sentinel light. (Metered sentinel lighting is captured under the consumption of the principal service.) The consumption for these customers is assumed to have the same hourly consumption load profile as for Street Lighting.

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. 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.

Embedded Distributor
This classification applies to Norfolk Power, an electricity distributor licensed by the Board, that is provided electricity by means of Haldimand County Hydro's facilities.

MONTHLY RATES AND CHARGES

Residential Urban

Service Charge	$	11.85
Distribution Volumetric Rate	$/kWh	0.0313
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Residential Suburban

Service Charge	$	12.34
Distribution Volumetric Rate	$/kWh	0.0315
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	19.07
Distribution Volumetric Rate	$/kWh	0.0228
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Haldimand County Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0181

General Service 50 to 4,999 kW

Service Charge	$	34.65
Distribution Volumetric Rate	$/kW	6.0333
Retail Transmission Rate – Network Service Rate	$/kW	1.7362
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5597
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8417
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.7238
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	9.03
Distribution Volumetric Rate	$/kWh	0.0235
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.71
Distribution Volumetric Rate	$/kW	4.6915
Retail Transmission Rate – Network Service Rate	$/kW	1.3159
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2310
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.51
Distribution Volumetric Rate	$/kW	4.1081
Retail Transmission Rate – Network Service Rate	$/kW	1.3093
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2059
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Embedded Distributor

Monthly Distribution Wheeling Service Rate – Norfolk Power	$/kW	0.6201
Retail Transmission Rate – Network Service Rate – Norfolk Power	$/kW	2.6875
Retail Transmission Rate – Line and Transformation Connection Service Rate – Norfolk Power	$/kW	2.5293

Haldimand County Hydro Inc.
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EB-2008-0181

Specific Service Charges

Customer Administration		
Legal letter charge	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - 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
Temporary service install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Bell Canada Pole Rentals	$	18.08
Norfolk Pole Rentals – Billed	$	28.61
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)

Retail Service Charges (if applicable)

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0565
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0460
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Embedded Distributor - Norfolk Power	1.0253

RESIDENTIAL

Consumption 500 kWh		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			11.01			20.76	9.75	88.56%	24.67%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	2.22%
	Distribution Volumetric (kWh)	500	0.0305	15.25	500	0.0240	12.00	(3.25)	(21.31%)	14.26%
	Low Voltage Cost Rate Adder (kWh)	500	0.0009	0.45	500	0.0005	0.25	(0.20)	(44.44%)	0.30%
	LRAM & SSM Rate Rider (kWh)	500	0.0000	0.00	500	0.0022	1.10	1.10	#DIV/0!	1.31%
	Deferral & Variance A/C Rate Rider (kWh)	500	0.0000	0.00	500	(0.0008)	(0.40)	(0.40)	#DIV/0!	(0.48%)
	Sub-Total A - Distribution			**27.71**			**35.58**	**7.87**	**28.40%**	**42.29%**
	RTSR - Network (kWh)	528	0.0047	2.48	534	0.0051	2.72	0.24	9.69%	3.24%
	RSTR - Connection (kWh)	528	0.0043	2.27	534	0.0045	2.43	0.16	6.94%	2.89%
	Sub-Total B (includes A) Delivery			**32.46**			**40.73**	**8.27**	**25.47%**	**48.41%**
	Wholesale Market Rate (kWh)	528	0.0052	2.75	534	0.0052	2.78	0.03	1.09%	3.30%
	RRRP (kWh)	528	0.0013	0.69	534	0.0013	0.69	0.01	1.09%	0.83%
	DRC (kWh)	500	0.0070	3.50	500	0.0070	3.50	0.00	0.00%	4.16%
	Cost of Power Commodity (kWh)	528	0.0607	32.08	534	0.0607	32.42	0.35	1.09%	38.54%
	Total Bill Before Taxes			**71.47**			**80.13**	**8.65**	**12.11%**	**95.24%**
	GST		5.00%	3.57		5.00%	4.01	0.43	12.11%	4.76%
	Total Bill			**75.05**			**84.13**	**9.09**	**12.11%**	**100.00%**

RESIDENTIAL

Consumption 800 kWh		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			11.01			20.76	9.75	88.56%	17.25%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	1.55%
	Distribution Volumetric (kWh)	800	0.0305	24.40	800	0.0240	19.20	(5.20)	(21.31%)	15.95%
	Low Voltage Cost Rate Adder (kWh)	800	0.0009	0.72	800	0.0005	0.40	(0.32)	(44.44%)	0.33%
	LRAM & SSM Rate Rider (kWh)	800	0.0000	0.00	800	0.0022	1.76	1.76	#DIV/0!	1.46%
	Deferral & Variance A/C Rate Rider (kWh)	800	0.0000	0.00	800	(0.0008)	(0.64)	(0.64)	#DIV/0!	(0.53%)
	Sub-Total A - Distribution			**37.13**			**43.35**	**6.22**	**16.75%**	**36.02%**
	RTSR - Network (kWh)	845	0.0047	3.97	854	0.0051	4.36	0.38	9.69%	3.62%
	RSTR - Connection (kWh)	845	0.0043	3.63	854	0.0045	3.89	0.25	6.94%	3.23%
	Sub-Total B (includes A) Delivery			**44.74**			**51.59**	**6.86**	**15.33%**	**42.87%**
	Wholesale Market Rate (kWh)	845	0.0052	4.40	854	0.0052	4.44	0.05	1.09%	3.69%
	RRRP (kWh)	845	0.0013	1.10	854	0.0013	1.11	0.01	1.09%	0.92%
	DRC (kWh)	800	0.0070	5.60	800	0.0070	5.60	0.00	0.00%	4.65%
	Cost of Power Commodity (kWh)	845	0.0607	51.32	854	0.0607	51.88	0.56	1.09%	43.10%
	Total Bill Before Taxes			**107.15**			**114.63**	**7.47**	**6.97%**	**95.24%**
	GST		5.00%	5.36		5.00%	5.73	0.37	6.97%	4.76%
	Total Bill			**112.51**			**120.36**	**7.85**	**6.97%**	**100.00%**

RESIDENTIAL

Consumption 1,000 kWh		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			11.01			20.76	9.75	88.56%	14.37%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	1.29%
	Distribution Volumetric (kWh)	1,000	0.0305	30.50	1,000	0.0240	24.00	(6.50)	(21.31%)	16.61%
	Low Voltage Cost Rate Adder (kWh)	1,000	0.0009	0.90	1,000	0.0005	0.50	(0.40)	(44.44%)	0.35%
	LRAM & SSM Rate Rider (kWh)	1,000	0.0000	0.00	1,000	0.0022	2.20	2.20	#DIV/0!	1.52%
	Deferral & Variance A/C Rate Rider (kWh)	1,000	0.0000	0.00	1,000	(0.0008)	(0.80)	(0.80)	#DIV/0!	(0.55%)
	Sub-Total A - Distribution			**43.41**			**48.53**	**5.12**	**11.79%**	**33.58%**
	RTSR - Network (kWh)	1,057	0.0047	4.97	1,068	0.0051	5.45	0.48	9.69%	3.77%
	RSTR - Connection (kWh)	1,057	0.0043	4.54	1,068	0.0045	4.86	0.32	6.94%	3.36%
	Sub-Total B (includes A) Delivery			**52.92**			**58.84**	**5.92**	**11.18%**	**40.71%**
	Wholesale Market Rate (kWh)	1,057	0.0052	5.49	1,068	0.0052	5.55	0.06	1.09%	3.84%
	RRRP (kWh)	1,057	0.0013	1.37	1,068	0.0013	1.39	0.01	1.09%	0.96%
	DRC (kWh)	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.00%	4.84%
	Cost of Power Commodity (kWh)	1,057	0.0607	64.15	1,068	0.0607	64.85	0.70	1.09%	44.88%
	Total Bill Before Taxes			**130.94**			**137.63**	**6.69**	**5.11%**	**95.24%**
	GST		5.00%	6.55		5.00%	6.88	0.33	5.11%	4.76%
	Total Bill			**137.49**			**144.51**	**7.02**	**5.11%**	**100.00%**

RESIDENTIAL

Consumption 2,500 kWh		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			11.01			20.76	9.75	88.56%	6.38%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.57%
	Distribution Volumetric (kWh)	2,500	0.0305	76.25	2,500	0.0240	60.00	(16.25)	(21.31%)	18.43%
	Low Voltage Cost Rate Adder (kWh)	2,500	0.0009	2.25	2,500	0.0005	1.25	(1.00)	(44.44%)	0.38%
	LRAM & SSM Rate Rider (kWh)	2,500	0.0000	0.00	2,500	0.0022	5.50	5.50	#DIV/0!	1.69%
	Deferral & Variance A/C Rate Rider (kWh)	2,500	0.0000	0.00	2,500	(0.0008)	(2.00)	(2.00)	#DIV/0!	(0.61%)
	Sub-Total A - Distribution			**90.51**			**87.38**	**(3.13)**	**(3.46%)**	**26.83%**
	RTSR - Network (kWh)	2,641	0.0047	12.41	2,670	0.0051	13.62	1.20	9.69%	4.18%
	RSTR - Connection (kWh)	2,641	0.0043	11.36	2,670	0.0045	12.15	0.79	6.94%	3.73%
	Sub-Total B (includes A) Delivery			**114.28**			**113.14**	**(1.14)**	**(1.00%)**	**34.75%**
	Wholesale Market Rate (kWh)	2,641	0.0052	13.73	2,670	0.0052	13.88	0.15	1.09%	4.26%
	RRRP (kWh)	2,641	0.0013	3.43	2,670	0.0013	3.47	0.04	1.09%	1.07%
	DRC (kWh)	2,500	0.0070	17.50	2,500	0.0070	17.50	0.00	0.00%	5.37%
	Cost of Power Commodity (kWh)	2,641	0.0607	160.38	2,670	0.0607	162.12	1.74	1.09%	49.79%
	Total Bill Before Taxes			**309.33**			**310.12**	**0.79**	**0.25%**	**95.24%**
	GST		5.00%	15.47		5.00%	15.51	0.04	0.25%	4.76%
	Total Bill			**324.80**			**325.63**	**0.83**	**0.25%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption 2,000 kWh		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			18.07			29.37	11.30	62.53%	11.22%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.71%
	Distribution Volumetric (kWh)	2,000	0.0220	44.00	2,000	0.0210	42.00	(2.00)	(4.55%)	16.04%
	Low Voltage Cost Rate Adder (kWh)	2,000	0.0008	1.60	2,000	0.0004	0.80	(0.80)	(50.00%)	0.31%
	LRAM & SSM Rate Rider (kWh)	2,000	0.0000	0.00	2,000	0.0001	0.20	0.20	#DIV/0!	0.08%
	Deferral & Variance A/C Rate Rider (kWh)	2,000	0.0000	0.00	2,000	(0.0005)	(1.00)	(1.00)	#DIV/0!	(0.38%)
	Sub-Total A - Distribution			**64.67**			**73.24**	**8.57**	**13.25%**	**27.97%**
	RTSR - Network (kWh)	2,113	0.0042	8.87	2,136	0.0045	9.71	0.84	9.46%	3.71%
	RSTR - Connection (kWh)	2,113	0.0039	8.24	2,136	0.0041	8.81	0.57	6.94%	3.37%
	Sub-Total B (includes A) Delivery			**81.79**			**91.77**	**9.98**	**12.21%**	**35.05%**
	Wholesale Market Rate (kWh)	2,113	0.0052	10.99	2,136	0.0052	11.11	0.12	1.09%	4.24%
	RRRP (kWh)	2,113	0.0013	2.75	2,136	0.0013	2.78	0.03	1.09%	1.06%
	DRC (kWh)	2,000	0.0070	14.00	2,000	0.0070	14.00	0.00	0.00%	5.35%
	Cost of Power Commodity (kWh)	2,113	0.0607	128.31	2,136	0.0607	129.70	1.39	1.09%	49.54%
	Total Bill Before Taxes			**237.83**			**249.35**	**11.52**	**4.85%**	**95.24%**
	GST		5.00%	11.89		5.00%	12.47	0.58	4.85%	4.76%
	Total Bill			**249.72**			**261.82**	**12.10**	**4.85%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption 5,000 kWh		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			18.07			29.37	11.30	62.53%	4.85%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.31%
	Distribution Volumetric (kWh)	5,000	0.0220	110.00	5,000	0.0210	105.00	(5.00)	(4.55%)	17.35%
	Low Voltage Cost Rate Adder (kWh)	5,000	0.0008	4.00	5,000	0.0004	2.00	(2.00)	(50.00%)	0.33%
	LRAM & SSM Rate Rider (kWh)	5,000	0.0000	0.00	5,000	0.0001	0.50	0.50	#DIV/0!	0.08%
	Deferral & Variance A/C Rate Rider (kWh)	5,000	0.0000	0.00	5,000	(0.0005)	(2.50)	(2.50)	#DIV/0!	(0.41%)
	Sub-Total A - Distribution			**133.07**			**136.24**	**3.17**	**2.38%**	**22.51%**
	RTSR - Network (kWh)	5,283	0.0042	22.19	5,340	0.0045	24.29	2.10	9.46%	4.01%
	RSTR - Connection (kWh)	5,283	0.0039	20.60	5,340	0.0041	22.03	1.43	6.94%	3.64%
	Sub-Total B (includes A) Delivery			**175.86**			**182.56**	**6.70**	**3.81%**	**30.16%**
	Wholesale Market Rate (kWh)	5,283	0.0052	27.47	5,340	0.0052	27.77	0.30	1.09%	4.59%
	RRRP (kWh)	5,283	0.0013	6.87	5,340	0.0013	6.94	0.07	1.09%	1.15%
	DRC (kWh)	5,000	0.0070	35.00	5,000	0.0070	35.00	0.00	0.00%	5.78%
	Cost of Power Commodity (kWh)	5,283	0.0607	320.76	5,340	0.0607	324.24	3.48	1.09%	53.56%
	Total Bill Before Taxes			**565.96**			**576.51**	**10.55**	**1.86%**	**95.24%**
	GST		5.00%	28.30		5.00%	28.83	0.53	1.86%	4.76%
	Total Bill			**594.26**			**605.34**	**11.08**	**1.86%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
10,000 kWh	Monthly Service Charge			18.07			29.37	11.30	62.53%	2.49%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.16%
	Distribution Volumetric (kWh)	10,000	0.0220	220.00	10,000	0.0210	210.00	(10.00)	(4.55%)	17.83%
	Low Voltage Cost Rate Adder (kWh)	10,000	0.0008	8.00	10,000	0.0004	4.00	(4.00)	(50.00%)	0.34%
	LRAM & SSM Rate Rider (kWh)	10,000	0.0000	0.00	10,000	0.0001	1.00	1.00	#DIV/0!	0.08%
	Deferral & Variance A/C Rate Rider (kWh)	10,000	0.0000	0.00	10,000	(0.0005)	(5.00)	(5.00)	#DIV/0!	(0.42%)
	Sub-Total A - Distribution			**247.07**			**241.24**	**(5.83)**	**(2.36%)**	**20.48%**
	RTSR - Network (kWh)	10,565	0.0042	44.37	10,680	0.0045	48.57	4.20	9.46%	4.12%
	RSTR - Connection (kWh)	10,565	0.0039	41.20	10,680	0.0041	44.07	2.86	6.94%	3.74%
	Sub-Total B (includes A) Delivery			**332.65**			**333.88**	**1.23**	**0.37%**	**28.35%**
	Wholesale Market Rate (kWh)	10,565	0.0052	54.94	10,680	0.0052	55.54	0.60	1.09%	4.71%
	RRRP (kWh)	10,565	0.0013	13.73	10,680	0.0013	13.88	0.15	1.09%	1.18%
	DRC (kWh)	10,000	0.0070	70.00	10,000	0.0070	70.00	0.00	0.00%	5.94%
	Cost of Power Commodity (kWh)	10,565	0.0607	641.53	10,680	0.0607	648.49	6.96	1.09%	55.06%
	Total Bill Before Taxes			**1,112.85**			**1,121.79**	**8.94**	**0.80%**	**95.24%**
	GST		5.00%	55.64		5.00%	56.09	0.45	0.80%	4.76%
	Total Bill			**1,168.49**			**1,177.88**	**9.39**	**0.80%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
15,000 kWh	Monthly Service Charge			18.07			29.37	11.30	62.53%	1.68%
	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.11%
	Distribution Volumetric (kWh)	15,000	0.0220	330.00	15,000	0.0210	315.00	(15.00)	(4.55%)	18.00%
	Low Voltage Cost Rate Adder (kWh)	15,000	0.0008	12.00	15,000	0.0004	6.00	(6.00)	(50.00%)	0.34%
	LRAM & SSM Rate Rider (kWh)	15,000	0.0000	0.00	15,000	0.0001	1.50	1.50	#DIV/0!	0.09%
	Deferral & Variance A/C Rate Rider (kWh)	15,000	0.0000	0.00	15,000	(0.0005)	(7.50)	(7.50)	#DIV/0!	(0.43%)
	Sub-Total A - Distribution			**361.07**			**346.24**	**(14.83)**	**(4.11%)**	**19.78%**
	RTSR - Network (kWh)	15,848	0.0042	66.56	16,020	0.0045	72.86	6.30	9.46%	4.16%
	RSTR - Connection (kWh)	15,848	0.0039	61.81	16,020	0.0041	66.10	4.29	6.94%	3.78%
	Sub-Total B (includes A) Delivery			**489.44**			**485.20**	**(4.24)**	**(0.87%)**	**27.72%**
	Wholesale Market Rate (kWh)	15,848	0.0052	82.41	16,020	0.0052	83.30	0.89	1.09%	4.76%
	RRRP (kWh)	15,848	0.0013	20.60	16,020	0.0013	20.83	0.22	1.09%	1.19%
	DRC (kWh)	15,000	0.0070	105.00	15,000	0.0070	105.00	0.00	0.00%	6.00%
	Cost of Power Commodity (kWh)	15,848	0.0607	962.29	16,020	0.0607	972.73	10.44	1.09%	55.57%
	Total Bill Before Taxes			**1,659.74**			**1,667.06**	**7.32**	**0.44%**	**95.24%**
	GST		5.00%	82.99		5.00%	83.35	0.37	0.44%	4.76%
	Total Bill			**1,742.73**			**1,750.42**	**7.69**	**0.44%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
20,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	4.78%
50 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.08%
	Distribution Volumetric (kW)	50	5.7064	285.32	50	4.9302	246.51	(38.81)	(13.60%)	11.12%
	Low Voltage Cost Rate Adder (kW)	50	0.3269	16.35	50	0.1825	9.13	(7.22)	(44.17%)	0.41%
	LRAM & SSM Rate Rider (kW)	50	0.0000	0.00	50	0.0414	2.07	2.07	#DIV/0!	0.09%
	Deferral & Variance A/C Rate Rider (kW)	50	0.0000	0.00	50	(0.1244)	(6.22)	(6.22)	#DIV/0!	(0.28%)
	Sub-Total A - Distribution			**336.32**			**359.27**	**22.95**	**6.82%**	**16.20%**
	RTSR - Network (kW)	50	1.7362	86.81	50	1.8801	94.00	7.19	8.29%	4.24%
	RSTR - Connection (kW)	50	1.5597	77.99	50	1.6501	82.51	4.52	5.80%	3.72%
	Sub-Total B (includes A) Delivery			**501.11**			**535.77**	**34.66**	**6.92%**	**24.16%**
	Wholesale Market Rate (kWh)	21,131	0.0052	109.88	21,360	0.0052	111.07	1.19	1.09%	5.01%
	RRRP (kWh)	21,131	0.0013	27.47	21,360	0.0013	27.77	0.30	1.09%	1.25%
	DRC (kWh)	20,000	0.0070	140.00	20,000	0.0070	140.00	0.00	0.00%	6.31%
	Cost of Power Commodity (kWh)	21,131	0.0607	1,283.05	21,360	0.0607	1,296.98	13.93	1.09%	58.50%
	Total Bill Before Taxes			**2,061.51**			**2,111.59**	**50.08**	**2.43%**	**95.24%**
	GST		5.00%	103.08		5.00%	105.58	2.50	2.43%	4.76%
	Total Bill			**2,164.59**			**2,217.17**	**52.58**	**2.43%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
50,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	2.15%
75 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.04%
	Distribution Volumetric (kW)	75	5.7064	427.98	75	4.9302	369.77	(58.22)	(13.60%)	7.51%
	Low Voltage Cost Rate Adder (kW)	75	0.3269	24.52	75	0.1825	13.69	(10.83)	(44.17%)	0.28%
	LRAM & SSM Rate Rider (kW)	75	0.0000	0.00	75	0.0414	3.11	3.11	#DIV/0!	0.06%
	Deferral & Variance A/C Rate Rider (kW)	75	0.0000	0.00	75	(0.1244)	(9.33)	(9.33)	#DIV/0!	(0.19%)
	Sub-Total A - Distribution			**487.15**			**485.01**	**(2.14)**	**(0.44%)**	**9.85%**
	RTSR - Network (kW)	75	1.7362	130.22	75	1.8801	141.01	10.79	8.29%	2.86%
	RSTR - Connection (kW)	75	1.5597	116.98	75	1.6501	123.76	6.78	5.80%	2.51%
	Sub-Total B (includes A) Delivery			**734.34**			**749.77**	**15.43**	**2.10%**	**15.23%**
	Wholesale Market Rate (kWh)	52,827	0.0052	274.70	53,400	0.0052	277.68	2.98	1.09%	5.64%
	RRRP (kWh)	52,827	0.0013	68.67	53,400	0.0013	69.42	0.75	1.09%	1.41%
	DRC (kWh)	50,000	0.0070	350.00	50,000	0.0070	350.00	0.00	0.00%	7.11%
	Cost of Power Commodity (kWh)	52,827	0.0607	3,207.63	53,400	0.0607	3,242.45	34.81	1.09%	65.85%
	Total Bill Before Taxes			**4,635.35**			**4,689.32**	**53.97**	**1.16%**	**95.24%**
	GST		5.00%	231.77		5.00%	234.47	2.70	1.16%	4.76%
	Total Bill			**4,867.12**			**4,923.78**	**56.67**	**1.16%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
75,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	1.47%
100 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.03%
	Distribution Volumetric (kW)	100	5.7064	570.64	100	4.9302	493.02	(77.62)	(13.60%)	6.83%
	Low Voltage Cost Rate Adder (kW)	100	0.3269	32.69	100	0.1825	18.25	(14.44)	(44.17%)	0.25%
	LRAM & SSM Rate Rider (kW)	100	0.0000	0.00	100	0.0414	4.14	4.14	#DIV/0!	0.06%
	Deferral & Variance A/C Rate Rider (kW)	100	0.0000	0.00	100	(0.1244)	(12.44)	(12.44)	#DIV/0!	(0.17%)
	Sub-Total A - Distribution			**637.98**			**610.75**	**(27.23)**	**(4.27%)**	**8.46%**
	RTSR - Network (kW)	100	1.7362	173.62	100	1.8801	188.01	14.39	8.29%	2.61%
	RSTR - Connection (kW)	100	1.5597	155.97	100	1.6501	165.01	9.04	5.80%	2.29%
	Sub-Total B (includes A) Delivery			**967.57**			**963.77**	**(3.80)**	**(0.39%)**	**13.35%**
	Wholesale Market Rate (kWh)	79,240	0.0052	412.05	80,100	0.0052	416.52	4.47	1.09%	5.77%
	RRRP (kWh)	79,240	0.0013	103.01	80,100	0.0013	104.13	1.12	1.09%	1.44%
	DRC (kWh)	75,000	0.0070	525.00	75,000	0.0070	525.00	0.00	0.00%	7.27%
	Cost of Power Commodity (kWh)	79,240	0.0607	4,811.45	80,100	0.0607	4,863.67	52.22	1.09%	67.39%
	Total Bill Before Taxes			**6,819.08**			**6,873.09**	**54.01**	**0.79%**	**95.24%**
	GST		5.00%	340.95		5.00%	343.65	2.70	0.79%	4.76%
	Total Bill			**7,160.04**			**7,216.74**	**56.71**	**0.79%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
100,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	1.04%
200 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.02%
	Distribution Volumetric (kW)	200	5.7064	1,141.28	200	4.9302	986.04	(155.24)	(13.60%)	9.68%
	Low Voltage Cost Rate Adder (kW)	200	0.3269	65.38	200	0.1825	36.50	(28.88)	(44.17%)	0.36%
	LRAM & SSM Rate Rider (kW)	200	0.0000	0.00	200	0.0414	8.28	8.28	#DIV/0!	0.08%
	Deferral & Variance A/C Rate Rider (kW)	200	0.0000	0.00	200	(0.1244)	(24.88)	(24.88)	#DIV/0!	(0.24%)
	Sub-Total A - Distribution			**1,241.31**			**1,113.72**	**(127.59)**	**(10.28%)**	**10.94%**
	RTSR - Network (kW)	200	1.7362	347.24	200	1.8801	376.01	28.77	8.29%	3.69%
	RSTR - Connection (kW)	200	1.5597	311.94	200	1.6501	330.02	18.08	5.80%	3.24%
	Sub-Total B (includes A) Delivery			**1,900.49**			**1,819.76**	**(80.73)**	**(4.25%)**	**17.87%**
	Wholesale Market Rate (kWh)	105,653	0.0052	549.40	106,800	0.0052	555.36	5.96	1.09%	5.45%
	RRRP (kWh)	105,653	0.0013	137.35	106,800	0.0013	138.84	1.49	1.09%	1.36%
	DRC (kWh)	100,000	0.0070	700.00	100,000	0.0070	700.00	0.00	0.00%	6.87%
	Cost of Power Commodity (kWh)	105,653	0.0607	6,415.27	106,800	0.0607	6,484.90	69.63	1.09%	63.68%
	Total Bill Before Taxes			**9,702.51**			**9,698.85**	**(3.65)**	**(0.04%)**	**95.24%**
	GST		5.00%	485.13		5.00%	484.94	(0.18)	(0.04%)	4.76%
	Total Bill			**10,187.63**			**10,183.79**	**(3.84)**	**(0.04%)**	**100.00%**

GENERAL SERVICE (> 50 kW) INTERVAL METERED

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
100,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	1.03%
200 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.02%
	Distribution Volumetric (kW)	200	5.7064	1,141.28	200	4.9302	986.04	(155.24)	(13.60%)	9.57%
	Low Voltage Cost Rate Adder (kW)	200	0.3269	65.38	200	0.1825	36.50	(28.88)	(44.17%)	0.35%
	LRAM & SSM Rate Rider (kW)	200	0.0000	0.00	200	0.0414	8.28	8.28	#DIV/0!	0.08%
	Deferral & Variance A/C Rate Rider (kW)	200	0.0000	0.00	200	(0.1244)	(24.88)	(24.88)	#DIV/0!	(0.24%)
	Sub-Total A - Distribution			**1,241.31**			**1,113.72**	**(127.59)**	**(10.28%)**	**10.81%**
	RTSR - Network (kW)	211	1.8417	389.16	214	1.9943	425.98	36.82	9.46%	4.14%
	RSTR - Connection (kW)	211	1.7238	364.25	214	1.8237	389.55	25.30	6.94%	3.78%
	Sub-Total B (includes A) Delivery			**1,994.72**			**1,929.25**	**(65.47)**	**(3.28%)**	**18.73%**
	Wholesale Market Rate (kWh)	105,653	0.0052	549.40	106,800	0.0052	555.36	5.96	1.09%	5.39%
	RRRP (kWh)	105,653	0.0013	137.35	106,800	0.0013	138.84	1.49	1.09%	1.35%
	DRC (kWh)	100,000	0.0070	700.00	100,000	0.0070	700.00	0.00	0.00%	6.80%
	Cost of Power Commodity (kWh)	105,653	0.0607	6,415.27	106,800	0.0607	6,484.90	69.63	1.09%	62.97%
	Total Bill Before Taxes			**9,796.74**			**9,808.35**	**11.61**	**0.12%**	**95.24%**
	GST		5.00%	489.84		5.00%	490.42	0.58	0.12%	4.76%
	Total Bill			**10,286.58**			**10,298.77**	**12.19**	**0.12%**	**100.00%**

GENERAL SERVICE (> 50 kW) INTERVAL METERED

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
250,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	0.41%
500 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.01%
	Distribution Volumetric (kW)	500	5.7064	2,853.20	500	4.9302	2,465.10	(388.10)	(13.60%)	9.64%
	Low Voltage Cost Rate Adder (kW)	500	0.3269	163.45	500	0.1825	91.25	(72.20)	(44.17%)	0.36%
	LRAM & SSM Rate Rider (kW)	500	0.0000	0.00	500	0.0414	20.70	20.70	#DIV/0!	0.08%
	Deferral & Variance A/C Rate Rider (kW)	500	0.0000	0.00	500	(0.1244)	(62.20)	(62.20)	#DIV/0!	(0.24%)
	Sub-Total A - Distribution			**3,051.30**			**2,622.63**	**(428.67)**	**(14.05%)**	**10.25%**
	RTSR - Network (kW)	528	1.8417	972.91	534	1.9943	1,064.96	92.05	9.46%	4.16%
	RSTR - Connection (kW)	528	1.7238	910.63	534	1.8237	973.87	63.24	6.94%	3.81%
	Sub-Total B (includes A) Delivery			**4,934.83**			**4,661.46**	**(273.37)**	**(5.54%)**	**18.23%**
	Wholesale Market Rate (kWh)	264,133	0.0052	1,373.49	267,000	0.0052	1,388.40	14.91	1.09%	5.43%
	RRRP (kWh)	264,133	0.0013	343.37	267,000	0.0013	347.10	3.73	1.09%	1.36%
	DRC (kWh)	250,000	0.0070	1,750.00	250,000	0.0070	1,750.00	0.00	0.00%	6.84%
	Cost of Power Commodity (kWh)	264,133	0.0607	16,038.17	267,000	0.0607	16,212.24	174.07	1.09%	63.39%
	Total Bill Before Taxes			**24,439.87**			**24,359.20**	**(80.67)**	**(0.33%)**	**95.24%**
	GST		5.00%	1,221.99		5.00%	1,217.96	(4.03)	(0.33%)	4.76%
	Total Bill			**25,661.87**			**25,577.16**	**(84.71)**	**(0.33%)**	**100.00%**

GENERAL SERVICE (> 50 kW) INTERVAL METERED

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
500,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	0.21%
1,000 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.00%
	Distribution Volumetric (kW)	1,000	5.7064	5,706.40	1,000	4.9302	4,930.20	(776.20)	(13.60%)	9.66%
	Low Voltage Cost Rate Adder (kW)	1,000	0.3269	326.90	1,000	0.1825	182.50	(144.40)	(44.17%)	0.36%
	LRAM & SSM Rate Rider (kW)	1,000	0.0000	0.00	1,000	0.0414	41.40	41.40	#DIV/0!	0.08%
	Deferral & Variance A/C Rate Rider (kW)	1,000	0.0000	0.00	1,000	(0.1244)	(124.40)	(124.40)	#DIV/0!	(0.24%)
	Sub-Total A - Distribution			**6,067.95**			**5,137.48**	**(930.47)**	**(15.33%)**	**10.07%**
	RTSR - Network (kW)	1,057	1.8417	1,945.82	1,068	1.9943	2,129.92	184.11	9.46%	4.17%
	RSTR - Connection (kW)	1,057	1.7238	1,821.25	1,068	1.8237	1,947.74	126.49	6.94%	3.82%
	Sub-Total B (includes A) Delivery			**9,835.02**			**9,215.14**	**(619.88)**	**(6.30%)**	**18.05%**
	Wholesale Market Rate (kWh)	528,267	0.0052	2,746.99	534,000	0.0052	2,776.80	29.81	1.09%	5.44%
	RRRP (kWh)	528,267	0.0013	686.75	534,000	0.0013	694.20	7.45	1.09%	1.36%
	DRC (kWh)	500,000	0.0070	3,500.00	500,000	0.0070	3,500.00	0.00	0.00%	6.86%
	Cost of Power Commodity (kWh)	528,267	0.0607	32,076.34	534,000	0.0607	32,424.48	348.14	1.09%	63.53%
	Total Bill Before Taxes			**48,845.10**			**48,610.62**	**(234.48)**	**(0.48%)**	**95.24%**
	GST		5.00%	2,442.25		5.00%	2,430.53	(11.72)	(0.48%)	4.76%
	Total Bill			**51,287.35**			**51,041.15**	**(246.20)**	**(0.48%)**	**100.00%**

GENERAL SERVICE (> 50 kW) INTERVAL METERED

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
800,000 kWh	Monthly Service Charge			33.65			105.91	72.26	214.74%	0.11%
2,750 kW	Smart Meter Funding Adder (per month)			1.00			1.87	0.87	87.00%	0.00%
	Distribution Volumetric (kW)	2,750	5.7064	15,692.60	2,750	4.9302	13,558.05	(2,134.55)	(13.60%)	14.64%
	Low Voltage Cost Rate Adder (kW)	2,750	0.3269	898.98	2,750	0.1825	501.88	(397.10)	(44.17%)	0.54%
	LRAM & SSM Rate Rider (kW)	2,750	0.0000	0.00	2,750	0.0414	113.85	113.85	#DIV/0!	0.12%
	Deferral & Variance A/C Rate Rider (kW)	2,750	0.0000	0.00	2,750	(0.1244)	(342.10)	(342.10)	#DIV/0!	(0.37%)
	Sub-Total A - Distribution			**16,626.23**			**13,939.46**	**(2,686.77)**	**(16.16%)**	**15.05%**
	RTSR - Network (kW)	2,905	1.8417	5,351.00	2,937	1.9943	5,857.29	506.29	9.46%	6.33%
	RSTR - Connection (kW)	2,905	1.7238	5,008.44	2,937	1.8237	5,356.28	347.83	6.94%	5.78%
	Sub-Total B (includes A) Delivery			**26,985.66**			**25,153.02**	**(1,832.65)**	**(6.79%)**	**27.16%**
	Wholesale Market Rate (kWh)	845,226	0.0052	4,395.18	854,400	0.0052	4,442.88	47.70	1.09%	4.80%
	RRRP (kWh)	845,226	0.0013	1,098.79	854,400	0.0013	1,110.72	11.93	1.09%	1.20%
	DRC (kWh)	800,000	0.0070	5,600.00	800,000	0.0070	5,600.00	0.00	0.00%	6.05%
	Cost of Power Commodity (kWh)	845,226	0.0607	51,322.15	854,400	0.0607	51,879.17	557.02	1.09%	56.03%
	Total Bill Before Taxes			**89,401.79**			**88,185.79**	**(1,216.00)**	**(1.36%)**	**95.24%**
	GST		5.00%	4,470.09		5.00%	4,409.29	(60.80)	(1.36%)	4.76%
	Total Bill			**93,871.88**			**92,595.07**	**(1,276.80)**	**(1.36%)**	**100.00%**

Street Lighting

Billing Determinants		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
2,845 Connections	Monthly Service Charge	2,845	1.51	4,295.95	2,845	3.89	11,067.05	6,771.10	157.62%	32.96%
200,000 kWh	Distribution Volumetric (kW)	535	3.8651	2,067.83	535	9.9657	5,331.65	3,263.82	157.84%	15.88%
535 kW	Low Voltage Cost Rate Adder (kW)	535	0.2430	130.01	535	0.1312	70.19	(59.81)	(46.01%)	0.21%
	Deferral & Variance A/C Rate Rider (kW)	535	0.0000	0.00	535	(3.1629)	(1,692.15)	(1,692.15)	#DIV/0!	(5.04%)
	Sub-Total A - Distribution			**6,493.78**			**14,776.74**	**8,282.96**	**127.55%**	**44.01%**
	RTSR - Network (kW)	535	1.3093	700.48	535	1.4178	758.52	58.04	8.29%	2.26%
	RSTR - Connection (kW)	535	1.2059	645.16	535	1.2758	682.55	37.40	5.80%	2.03%
	Sub-Total B (includes A) Delivery			**7,839.42**			**16,217.81**	**8,378.40**	**106.88%**	**48.30%**
	Wholesale Market Rate (kWh)	211,307	0.0052	1,098.79	213,600	0.0052	1,110.72	11.93	1.09%	3.31%
	RRRP (kWh)	211,307	0.0013	274.70	213,600	0.0013	277.68	2.98	1.09%	0.83%
	DRC (kWh)	200,000	0.0070	1,400.00	200,000	0.0070	1,400.00	0.00	0.00%	4.17%
	Cost of Power Commodity (kWh)	211,307	0.0607	12,830.54	213,600	0.0607	12,969.79	139.25	1.09%	38.63%
	Total Bill Before Taxes			**23,443.45**			**31,976.01**	**8,532.56**	**36.40%**	**95.24%**
	GST		5.00%	1,172.17		5.00%	1,598.80	426.63	36.40%	4.76%
	Total Bill			**24,615.62**			**33,574.81**	**8,959.19**	**36.40%**	**100.00%**

Street Lighting

Billing Determinants		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	1.51	1.51	1	3.89	3.89	2.38	157.62%	8.65%
372.00 kWh	Distribution Volumetric (kW)	1	3.8651	3.87	1	9.9657	9.97	6.10	157.84%	22.16%
1.00 kW	Low Voltage Cost Rate Adder (kW)	1	0.2430	0.24	1	0.1312	0.13	(0.11)	(46.01%)	0.29%
	Deferral & Variance A/C Rate Rider (kW)	1	0.0000	0.00	1	(3.1629)	(3.16)	(3.16)	#DIV/0!	(7.03%)
	Sub-Total A - Distribution			**5.62**			**10.82**	**5.21**	**92.66%**	**24.07%**
	RTSR - Network (kW)	1	1.3093	1.31	1	1.4178	1.42	0.11	8.29%	3.15%
	RSTR - Connection (kW)	1	1.2059	1.21	1	1.2758	1.28	0.07	5.80%	2.84%
	Sub-Total B (includes A) Delivery			**8.13**			**13.52**	**5.38**	**66.20%**	**30.06%**
	Wholesale Market Rate (kWh)	393	0.0052	2.04	397	0.0052	2.07	0.02	1.09%	4.59%
	RRRP (kWh)	393	0.0013	0.51	397	0.0013	0.52	0.01	1.09%	1.15%
	DRC (kWh)	372	0.0070	2.60	372	0.0070	2.60	0.00	0.00%	5.79%
	Cost of Power Commodity (kWh)	393	0.0607	23.86	397	0.0607	24.12	0.26	1.09%	53.65%
	Total Bill Before Taxes			**37.16**			**42.83**	**5.67**	**15.26%**	**95.24%**
	GST		5.00%	1.86		5.00%	2.14	0.28	15.26%	4.76%
	Total Bill			**39.01**			**44.97**	**5.95**	**15.26%**	**100.00%**

Street Lighting

Billing Determinants
18 Connections
1,643.00 kWh
4.50 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	18	1.51	27.18	18	3.89	70.02	42.84	157.62%	27.47%
Distribution Volumetric (kW)	4.5	3.8651	17.39	4.5	9.9657	44.85	27.45	157.84%	17.59%
Low Voltage Cost Rate Adder (kW)	4.5	0.2430	1.09	4.5	0.1312	0.59	(0.50)	(46.01%)	0.23%
Deferral & Variance A/C Rate Rider (kW)	4.5	0.0000	0.00	4.5	(3.1629)	(14.23)	(14.23)	#DIV/0!	(5.58%)
Sub-Total A - Distribution			**45.67**			**101.22**	**55.56**	**121.66%**	**39.71%**
RTSR - Network (kW)	4.5	1.3093	5.89	4.5	1.4178	6.38	0.49	8.29%	2.50%
RSTR - Connection (kW)	4.5	1.2059	5.43	4.5	1.2758	5.74	0.31	5.80%	2.25%
Sub-Total B (includes A) Delivery			**56.98**			**113.34**	**56.36**	**98.90%**	**44.46%**
Wholesale Market Rate (kWh)	1,736	0.0052	9.03	1,755	0.0052	9.12	0.10	1.09%	3.58%
RRRP (kWh)	1,736	0.0013	2.26	1,755	0.0013	2.28	0.02	1.09%	0.89%
DRC (kWh)	1,643	0.0070	11.50	1,643	0.0070	11.50	0.00	0.00%	4.51%
Cost of Power Commodity (kWh)	1,736	0.0607	105.40	1,755	0.0607	106.55	1.14	1.09%	41.79%
Total Bill Before Taxes			**185.17**			**242.80**	**57.63**	**31.12%**	**95.24%**
GST		5.00%	9.26		5.00%	12.14	2.88	31.12%	4.76%
Total Bill			**194.43**			**254.94**	**60.51**	**31.12%**	**100.00%**

Sentinel Lights

Billing Determinants		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	1.71	1.71	1	7.39	7.39	5.68	332.16%	57.82%
36.50 kWh	Distribution Volumetric (kW)	0.10	4.4093	0.44	0.10	19.0586	1.91	1.46	332.24%	14.91%
0.10 kW	Low Voltage Cost Rate Adder (kW)	0.10	0.2822	0.03	0.10	0.1340	0.01	(0.01)	(52.52%)	0.10%
	Deferral & Variance A/C Rate Rider (kW)	0.10	0.0000	0.00	0.10	(2.8645)	(0.29)	(0.29)	#DIV/0!	(2.24%)
	Sub-Total A - Distribution			**2.18**			**9.02**	**6.84**	**314.05%**	**70.60%**
	RTSR - Network (kW)	0.10	1.3159	0.13	0.10	1.4249	0.14	0.01	8.29%	1.11%
	RSTR - Connection (kW)	0.10	1.2310	0.12	0.10	1.3024	0.13	0.01	5.80%	1.02%
	Sub-Total B (includes A) Delivery			**2.43**			**9.30**	**6.86**	**281.93%**	**72.74%**
	Wholesale Market Rate (kWh)	39	0.0052	0.20	39	0.0052	0.20	0.00	1.09%	1.59%
	RRRP (kWh)	39	0.0013	0.05	39	0.0013	0.05	0.00	1.09%	0.40%
	DRC (kWh)	37	0.0070	0.26	37	0.0070	0.26	0.00	0.00%	2.00%
	Cost of Power Commodity (kWh)	39	0.0607	2.34	39	0.0607	2.37	0.03	1.09%	18.52%
	Total Bill Before Taxes			**5.28**			**12.17**	**6.89**	**130.45%**	**95.24%**
	GST		5.00%	0.26		5.00%	0.61	0.34	130.45%	4.76%
	Total Bill			**5.55**			**12.78**	**7.23**	**130.45%**	**100.00%**

Sentinel Lights

Billing Determinants		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	1.71	1.71	1	7.39	7.39	5.68	332.16%	40.37%
76.70 kWh	Distribution Volumetric (kW)	0.21	4.4093	0.93	0.21	19.0586	4.00	3.08	332.24%	21.86%
0.21 kW	Low Voltage Cost Rate Adder (kW)	0.21	0.2822	0.06	0.21	0.1340	0.03	(0.03)	(52.52%)	0.15%
	Deferral & Variance A/C Rate Rider (kW)	0.21	0.0000	0.00	0.21	(2.8645)	(0.60)	(0.60)	#DIV/0!	(3.29%)
	Sub-Total A - Distribution			**2.70**			**10.82**	**8.12**	**301.41%**	**59.10%**
	RTSR - Network (kW)	0.21	1.3159	0.28	0.21	1.4249	0.30	0.02	8.29%	1.63%
	RSTR - Connection (kW)	0.21	1.2310	0.26	0.21	1.3024	0.27	0.01	5.80%	1.49%
	Sub-Total B (includes A) Delivery			**3.23**			**11.39**	**8.16**	**252.68%**	**62.23%**
	Wholesale Market Rate (kWh)	81	0.0052	0.42	82	0.0052	0.43	0.00	1.09%	2.33%
	RRRP (kWh)	81	0.0013	0.11	82	0.0013	0.11	0.00	1.09%	0.58%
	DRC (kWh)	77	0.0070	0.54	77	0.0070	0.54	0.00	0.00%	2.93%
	Cost of Power Commodity (kWh)	81	0.0607	4.92	82	0.0607	4.97	0.05	1.09%	27.17%
	Total Bill Before Taxes			**9.21**			**17.43**	**8.22**	**89.22%**	**95.24%**
	GST		5.00%	0.46		5.00%	0.87	0.41	89.22%	4.76%
	Total Bill			**9.67**			**18.31**	**8.63**	**89.22%**	**100.00%**

Sentinel Lights

Billing Determinants		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	1.71	1.71	1	7.39	7.39	5.68	332.16%	33.64%
104.00 kWh	Distribution Volumetric (kW)	0.28	4.4093	1.23	0.28	19.0586	5.34	4.10	332.24%	24.29%
0.28 kW	Low Voltage Cost Rate Adder (kW)	0.28	0.2822	0.08	0.28	0.1340	0.04	(0.04)	(52.52%)	0.17%
	Deferral & Variance A/C Rate Rider (kW)	0.28	0.0000	0.00	0.28	(2.8645)	(0.80)	(0.80)	#DIV/0!	(3.65%)
	Sub-Total A - Distribution			**3.02**			**11.96**	**8.94**	**295.61%**	**54.46%**
	RTSR - Network (kW)	0.28	1.3159	0.37	0.28	1.4249	0.40	0.03	8.29%	1.82%
	RSTR - Connection (kW)	0.28	1.2310	0.34	0.28	1.3024	0.36	0.02	5.80%	1.66%
	Sub-Total B (includes A) Delivery			**3.74**			**12.73**	**8.99**	**240.55%**	**57.93%**
	Wholesale Market Rate (kWh)	110	0.0052	0.57	111	0.0052	0.58	0.01	1.09%	2.63%
	RRRP (kWh)	110	0.0013	0.14	111	0.0013	0.14	0.00	1.09%	0.66%
	DRC (kWh)	104	0.0070	0.73	104	0.0070	0.73	0.00	0.00%	3.31%
	Cost of Power Commodity (kWh)	110	0.0607	6.67	111	0.0607	6.74	0.07	1.09%	30.70%
	Total Bill Before Taxes			**11.85**			**20.92**	**9.07**	**76.53%**	**95.24%**
	GST		5.00%	0.59		5.00%	1.05	0.45	76.53%	4.76%
	Total Bill			**12.44**			**21.97**	**9.52**	**76.53%**	**100.00%**

Sentinel Lights

Billing Determinants		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1 Connections	Monthly Service Charge	1	1.71	1.71	1	7.39	7.39	5.68	332.16%	23.95%
167.90 kWh	Distribution Volumetric (kW)	0.46	4.4093	2.03	0.46	19.0586	8.77	6.74	332.24%	28.41%
0.46 kW	Low Voltage Cost Rate Adder (kW)	0.46	0.2822	0.13	0.46	0.1340	0.06	(0.07)	(52.52%)	0.20%
	Deferral & Variance A/C Rate Rider (kW)	0.46	0.0000	0.00	0.46	(2.8645)	(1.32)	(1.32)	#DIV/0!	(4.27%)
	Sub-Total A - Distribution			**3.87**			**14.90**	**11.03**	**285.23%**	**48.30%**
	RTSR - Network (kW)	0.46	1.3159	0.61	0.46	1.4249	0.66	0.05	8.29%	2.12%
	RSTR - Connection (kW)	0.46	1.2310	0.57	0.46	1.3024	0.60	0.03	5.80%	1.94%
	Sub-Total B (includes A) Delivery			**5.04**			**16.16**	**11.12**	**220.57%**	**52.36%**
	Wholesale Market Rate (kWh)	177	0.0052	0.92	179	0.0052	0.93	0.01	1.09%	3.02%
	RRRP (kWh)	177	0.0013	0.23	179	0.0013	0.23	0.00	1.09%	0.76%
	DRC (kWh)	168	0.0070	1.18	168	0.0070	1.18	0.00	0.00%	3.81%
	Cost of Power Commodity (kWh)	177	0.0607	10.77	179	0.0607	10.89	0.12	1.09%	35.29%
	Total Bill Before Taxes			**18.14**			**29.38**	**11.25**	**61.99%**	**95.24%**
	GST		5.00%	0.91		5.00%	1.47	0.56	61.99%	4.76%
	Total Bill			**19.05**			**30.85**	**11.81**	**61.99%**	**100.00%**

Unmetered Scattered Load

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
250 kWh	Monthly Service Charge			9.03			20.91	11.88	131.54%	45.83%
	Distribution Volumetric (kWh)	250	0.0226	5.65	250	0.0036	0.90	(4.75)	(84.07%)	1.97%
	Low Voltage Cost Rate Adder (kWh)	250	0.0009	0.23	250	0.0004	0.10	(0.13)	(55.56%)	0.22%
	Deferral & Variance A/C Rate Rider (kWh)	250	0.0000	0.00	250	(0.0019)	(0.48)	(0.48)	#DIV/0!	(1.04%)
	Sub-Total A - Distribution			**14.91**			**21.43**	**6.53**	**43.80%**	**46.98%**
	RTSR - Network (kWh)	264	0.0042	1.11	267	0.0045	1.21	0.10	9.46%	2.66%
	RSTR - Connection (kWh)	264	0.0039	1.03	267	0.0041	1.10	0.07	6.94%	2.41%
	Sub-Total B (includes A) Delivery			**17.04**			**23.75**	**6.70**	**39.33%**	**52.06%**
	Wholesale Market Rate (kWh)	264	0.0052	1.37	267	0.0052	1.39	0.01	1.09%	3.04%
	RRRP (kWh)	264	0.0013	0.34	267	0.0013	0.35	0.00	1.09%	0.76%
	DRC (kWh)	250	0.0070	1.75	250	0.0070	1.75	0.00	0.00%	3.84%
	Cost of Power Commodity (kWh)	264	0.0607	16.04	267	0.0607	16.21	0.17	1.09%	35.54%
	Total Bill Before Taxes			**36.55**			**43.45**	**6.90**	**18.87%**	**95.24%**
	GST		5.00%	1.83		5.00%	2.17	0.34	18.87%	4.76%
	Total Bill			**38.38**			**45.62**	**7.24**	**18.87%**	**100.00%**

Unmetered Scattered Load

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
500 kWh	Monthly Service Charge			9.03			20.91	11.88	131.54%	30.18%
	Distribution Volumetric (kWh)	500	0.0226	11.30	500	0.0036	1.80	(9.50)	(84.07%)	2.60%
	Low Voltage Cost Rate Adder (kWh)	500	0.0009	0.45	500	0.0004	0.20	(0.25)	(55.56%)	0.29%
	Deferral & Variance A/C Rate Rider (kWh)	500	0.0000	0.00	500	(0.0019)	(0.95)	(0.95)	#DIV/0!	(1.37%)
	Sub-Total A - Distribution			**20.78**			**21.96**	**1.18**	**5.67%**	**31.69%**
	RTSR - Network (kWh)	528	0.0042	2.22	534	0.0045	2.43	0.21	9.46%	3.51%
	RSTR - Connection (kWh)	528	0.0039	2.06	534	0.0041	2.20	0.14	6.94%	3.18%
	Sub-Total B (includes A) Delivery			**25.06**			**26.59**	**1.53**	**6.11%**	**38.38%**
	Wholesale Market Rate (kWh)	528	0.0052	2.75	534	0.0052	2.78	0.03	1.09%	4.01%
	RRRP (kWh)	528	0.0013	0.69	534	0.0013	0.69	0.01	1.09%	1.00%
	DRC (kWh)	500	0.0070	3.50	500	0.0070	3.50	0.00	0.00%	5.05%
	Cost of Power Commodity (kWh)	528	0.0607	32.08	534	0.0607	32.42	0.35	1.09%	46.80%
	Total Bill Before Taxes			**64.07**			**65.99**	**1.92**	**2.99%**	**95.24%**
	GST		5.00%	3.20		5.00%	3.30	0.10	2.99%	4.76%
	Total Bill			**67.27**			**69.28**	**2.01**	**2.99%**	**100.00%**

Unmetered Scattered Load

Consumption		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1,000 kWh	Monthly Service Charge			9.03			20.91	11.88	131.54%	17.93%
	Distribution Volumetric (kWh)	1,000	0.0226	22.60	1,000	0.0036	3.60	(19.00)	(84.07%)	3.09%
	Low Voltage Cost Rate Adder (kWh)	1,000	0.0009	0.90	1,000	0.0004	0.40	(0.50)	(55.56%)	0.34%
	Deferral & Variance A/C Rate Rider (kWh)	1,000	0.0000	0.00	1,000	(0.0019)	(1.90)	(1.90)	#DIV/0!	(1.63%)
	Sub-Total A - Distribution			**32.53**			**23.01**	**(9.52)**	**(29.27%)**	**19.73%**
	RTSR - Network (kWh)	1,057	0.0042	4.44	1,068	0.0045	4.86	0.42	9.46%	4.17%
	RSTR - Connection (kWh)	1,057	0.0039	4.12	1,068	0.0041	4.41	0.29	6.94%	3.78%
	Sub-Total B (includes A) Delivery			**41.09**			**32.27**	**(8.82)**	**(21.46%)**	**27.67%**
	Wholesale Market Rate (kWh)	1,057	0.0052	5.49	1,068	0.0052	5.55	0.06	1.09%	4.76%
	RRRP (kWh)	1,057	0.0013	1.37	1,068	0.0013	1.39	0.01	1.09%	1.19%
	DRC (kWh)	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.00%	6.00%
	Cost of Power Commodity (kWh)	1,057	0.0607	64.15	1,068	0.0607	64.85	0.70	1.09%	55.61%
	Total Bill Before Taxes			**119.11**			**111.06**	**(8.05)**	**(6.75%)**	**95.24%**
	GST		5.00%	5.96		5.00%	5.55	(0.40)	(6.75%)	4.76%
	Total Bill			**125.06**			**116.62**	**(8.45)**	**(6.75%)**	**100.00%**

Embedded Distributor - Hydro One Networks Inc.

Consumption
6,932,073 kWh
23,079 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			34.65			191.77	157.12	453.45%	0.03%
Distribution (kW)	23,079	6.0333	139,243.03	23,079	0.5610	12,947.37	(126,295.67)	(90.70%)	1.91%
Sub-Total A - Distribution			**139,277.68**			**13,139.14**	**(126,138.55)**	**(90.57%)**	**1.94%**
RTSR - Network (kW)	24,140	1.8417	44,458.60	23,783	2.3200	55,176.55	10,717.95	24.11%	8.13%
RSTR - Connection (kW)	24,140	1.7238	41,612.49	23,783	2.0660	49,134.75	7,522.25	18.08%	7.24%
Sub-Total B (includes A) Delivery			**225,348.77**			**117,450.43**	**(234,194.01)**	**(103.93%)**	**17.31%**
Wholesale Market Rate (kWh)	7,250,725	0.0052	37,703.77	7,143,501	0.0052	37,146.21	(557.56)	(1.48%)	5.48%
RRRP (kWh)	7,250,725	0.0013	9,425.94	7,143,501	0.0013	9,286.55	(139.39)	(1.48%)	1.37%
DRC (kWh)	6,932,073	0.0070	48,524.51	6,932,073	0.0070	48,524.51	0.00	0.00%	7.15%
Cost of Power Commodity (kWh)	7,250,725	0.0607	440,264.01	7,143,501	0.0607	433,753.39	(6,510.62)	(1.48%)	63.93%
Total Bill Before Taxes			**761,267.01**			**646,161.09**	**(133,206.73)**	**(17.50%)**	**95.24%**
GST		5.00%	38,063.35		5.00%	32,308.05	(5,755.30)	(15.12%)	4.76%
Total Bill			**799,330.36**			**678,469.14**	**(138,962.03)**	**(17.38%)**	**100.00%**

Exhibit	Tab	Schedule	Appendix	Contents
9 – Deferral and Variance Accounts				
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DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS AND BALANCES

This Schedule contains descriptions of Deferral and Variance Accounts ("DVAs") currently used by Haldimand County Hydro Inc. ("HCHI") and their balances as at December 31, 2008.

RSVA ACCOUNTS

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net difference between the amount billed to customers using the Board-approved Wholesale Market Service Rate, and the amount charged by the Independent Electricity System Operator ("IESO") based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: This account is used to record the net difference between the amount billed to customers using the Board-approved Transmission Network Charge Rate, and the amount charged by the IESO based on the settlement invoice for transmission network services.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: This account is used to record the net difference between the amount billed to customers using the Board-approved Transmission Connection Charge Rate, and the amount charged by the IESO based on the settlement invoice for transmission connection services.

1588 Retail Settlement Variance Account – Power

Description: This account is used to record the net difference between the energy amount billed to customers, and the energy charge to HCHI using the settlement invoice received from the IESO.

1588 Retail Settlement Variance Account – Power – Sub-account – Global Adjustment

Description: This account is used to record the net difference between the provincial benefit amount billed to non-Regulated Price Plan ("RPP") customers, and the global adjustment charge to HCHI for non-RPP customers using the settlement invoice received from the IESO.

The RSVA-Power account 1588 is designed to capture variances due to billing timing differences (i.e. electricity charged by IESO to LDCs vs. electricity billed by LDCs to their customers), price and quantity differences (i.e. arising from final vs. preliminary IESO settlement invoices), and line loss differences (i.e. actual vs. estimated line loss factors).

HCHI follows the accrual approach for record keeping and financial reporting for all DVAs, including the RSVA accounts.

NON RSVA ACCOUNTS

1508 Other Regulatory Assets - Sub-account – Pension Contributions

Description: This account is used to record pension costs associated with cash contribution amounts paid to OMERS for the period January 1, 2005 to April 30, 2006 and not included in rates. Effective May 1, 2006, pension cost contributions to OMERS were incorporated into the rates of HCHI.

1525 Miscellaneous Deferred Debits

Description: This account includes all debits not elsewhere provided for which will benefit future periods are carried forward and charged to expense over the term of the benefit. This account includes the cost of issuing refund cheques/credits to electricity consumers in accordance with government legislation, specifically the Bill 210 Rebates.

1555 Smart Meter Capital and Recovery Offset

Description: This account is used to record the capital costs directly related to the smart meter initiative and the revenue amounts charged to customers using the Board- approved smart meter funding adder.

1556 Smart Meter Operation, Maintenance and Administration

Description: This account is used to record the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters.

1562 Deferred Payments in Lieu of Taxes

Description: This account is used to record the difference between 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 ending April 30, 2006, and the actual amounts charged to customers that relate to the recovery of PILs.

1570 Qualifying Transition Costs

Description: This account is used to record the incremental costs incurred to prepare for and operate in a competitive commodity marketplace and that meet the four qualifying criteria established in the 2000 Electricity Distribution Rate Handbook. Entries to this account, other than carrying charges and amounts authorized by the Board, ceased on the electricity market opening on May 1, 2002.

1590 Recovery of Regulatory Asset Balances

Description: This account is used to record the difference between the regulatory asset and liability amounts approved by the Board for final disposition and recovery in rates effective May 1, 2006, and the associated revenues collected in rates over the approved recovery period of May 1, 2006 to April 30, 2008; that is, in addition to recording recoveries effective since April 1, 2004.

ACCOUNT BALANCES

The following Table 1 provides deferral and variance account balances as at December 31, 2008. These balances reconcile to those reported (i) in the audited financial statements as at and for the year ended December 31, 2008 and (ii) to the Board in the regulatory trial balance as part of the required RRR filing (as revised) submitted March 9, 2009.

Table 1
Deferral and Variance Account Balances as at December 31, 2008

Account Description	Account Number	Principal as of Dec. 31/08	Interest to Dec. 31/08	Total as of Dec. 31/08
RSVA Accounts				
RSVA - Wholesale Market Service Charge	1580	$ (883,697)	$ (35,226)	$ (918,923)
RSVA - Retail Transmission Network Charge	1584	$ (1,428)	$ (28,251)	$ (29,679)
RSVA - Retail Transmission Connection Charge	1586	$ 167,836	$ (17,071)	$ 150,764
RSVA - Power	1588	$ (143,201)	$ 367,241	$ 224,040
RSVA - Power - Global Adjustment	1588	$ 214,151	$ 23,806	$ 237,957
Sub-total RSVA Accounts		$ (646,340)	$ 310,499	$ (335,840)
Non RSVA Accounts				
Other Regulatory Assets - Pension Contributions	1508	$ 178,327	$ 25,100	$ 203,428
Retail Cost Variance Account - Retail	1518	$ 313,279	$ 34,474	$ 347,753
Retail Cost Variance Account - STR	1548	$ 3,781	$ 1,015	$ 4,795
Miscellaneous Deferred Debits	1525	$ -	$ 0	$ 0
LV Variance Account	1550	$ (280,877)	$ (21,635)	$ (302,512)
Smart Meter Capital - Capital	1555	$ 130,896	$ (2,958)	$ 127,938
Smart Meter Capital - Recoveries	1555	$ (164,894)	$ -	$ (164,894)
Smart Meter OM&A	1556	$ -	$ -	$ -
Qualifying Transition Costs	1570	$ (407,342)	$ (117,669)	$ (525,011)
Pre-Market Opening Energy Variance	1571	$ (0)	$ (0)	$ (0)
Deferred Payments in Lieu of Taxes	1562	$ 764,050	$ 221,833	$ 985,884
Recovery of Regulatory Asset Balances	1590	$ 489,653	$ (103,125)	$ 386,528
Sub-total Non RSVA Accounts		$ 1,026,872	$ 37,036	$ 1,063,908
Total Deferral and Variance Accounts		$ 380,532	$ 347,535	$ 728,068

Appendix A "Deferral and Variance Accounts – Continuity Schedule" provides the continuity schedule for the period January 1, 2005 to December 31, 2008, showing separate itemization of opening balances, annual adjustments, accruals, interest and closing balances. It also provides the projected carrying charges for each DVA to the proposed rate rider implementation date of May 1, 2010.

The opening principal and interest balances as of January 1, 2005 represent the last Board-approved balances as of December 31, 2004. These balances were approved by the Board as part of HCHI's 2006 EDR Application – Board file no. EB-2005-0373 – and have been transferred to Account 1590 as required effective May 1, 2006.

Account balances include carrying charges which are calculated using simple interest applied to the monthly opening balance less any accumulated interest in the account. HCHI follows the accrual approach for record keeping and financial reporting and follows the same approach when calculating carrying charges. Interest rates used by HCHI to record carrying charges are consistent with the Board's prescribed rates for the respective quarterly period, as provided in Table 2 below.

Table 2
Prescribed Interest Rates for Deferral and Variance Accounts

	2005		2006		2007	2008	2009	2010
	Pension Contributions		Pension Contributions					
January	3.88%	7.25%	3.88%	7.25%	4.59%	5.14%	2.45%	0.55%
February	3.88%	7.25%	3.88%	7.25%	4.59%	5.14%	2.45%	0.55%
March	3.88%	7.25%	3.88%	7.25%	4.59%	5.14%	2.45%	0.55%
April	3.88%	7.25%	3.88%	7.25%	4.59%	4.08%	1.00%	0.55%
May	3.88%	7.25%	4.14%		4.59%	4.08%	1.00%	
June	3.88%	7.25%	4.14%		4.59%	4.08%	1.00%	
July	3.88%	7.25%	4.59%		4.59%	3.35%	0.55%	*(Note: 1)*
August	3.88%	7.25%	4.59%		4.59%	3.35%	0.55%	
September	3.88%	7.25%	4.59%		4.59%	3.35%	0.55%	
October	3.88%	7.25%	4.59%		5.14%	3.35%	0.55%	
November	3.88%	7.25%	4.59%		5.14%	3.35%	0.55%	
December	3.88%	7.25%	4.59%		5.14%	3.35%	0.55%	

Note: 1 At the time of filing, the last quarterly interest rate published by the Board was on June 22, 2009 for Q3 2009. This rate has been applied to the forecasted carrying charges calculated to the rate implementation date of May 1, 2010.

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

In a letter dated February 19, 2008, the Board initiated a process – Board file no. EB-2008-0046 – to review the electricity distributor's deferral and variance accounts ("EDDVAR"). On April 1, 2009 Board staff issued a discussion paper entitled "*Board Staff Discussion Paper on Electricity Distributors' Deferral and Variance Account Review*" for stakeholder comment. On July 31, 2009 the Board issued its "*Report on Electricity Distributors' Deferral and Variance Account Review Initiative*" ("Board Report"), which sets out the Board's policy for the annual review and disposition of deferral and variance accounts in a rebasing year, including filing guidelines. In accordance with the Board Report, HCHI is requesting the disposition of the following deferral and variance accounts as set out in Table 3, which include the closing principal and interest as of December 31, 2008 and the projected interest from January 1, 2009 to April 30, 2010 calculated on the closing principal balance as of December 31, 2008.

Table 3
Deferral and Variance Accounts Requested For Disposition

Account Description	Account Number	Principal as of Dec. 31/08	Interest as of Dec. 31/08	Interest Forecast to Dec. 31/09	Interest Forecast to Apr. 30/10	Total Claim
RSVA Accounts						
RSVA - Wholesale Market Service Charge	1580	$ (883,697)	$ (35,226)	$ (10,052)	$ (1,620)	$ (930,595)
RSVA - Retail Transmission Network Charge	1584	$ (1,428)	$ (28,251)	$ (16)	$ (3)	$ (29,698)
RSVA - Retail Transmission Connection Charge	1586	$ 167,836	$ (17,071)	$ 1,909	$ 308	$ 152,981
RSVA - Power	1588	$ (143,201)	$ 367,241	$ (1,629)	$ (263)	$ 222,149
RSVA - Power - Global Adjustment	1588	$ 214,151	$ 23,806	$ 2,436	$ 393	$ 240,786
Sub-total RSVA Accounts		$ (646,340)	$ 310,499	$ (7,352)	$ (1,185)	$ (344,377)
Non RSVA Accounts						
Other Regulatory Assets - Pension Cont'n.	1508	$ 178,327	$ 25,100	$ 2,028	$ 327	$ 205,783
Retail Cost Variance Account - Retail	1518	$ 313,279	$ 34,474	$ 3,564	$ 574	$ 351,891
Retail Cost Variance Account - STR	1548	$ 3,781	$ 1,015	$ 43	$ 7	$ 4,845
LV Variance Account	1550	$ (280,877)	$ (21,635)	$ (3,195)	$ (515)	$ (306,222)
Qualifying Transition Costs	1570	$ (407,342)	$ (117,669)	$ (4,634)	$ (747)	$ (530,391)
Recovery of Regulatory Asset Balances	1590	$ 489,653	$ (103,125)	$ 5,570	$ 898	$ 392,995
Sub-total Non RSVA Accounts		$ 296,820	$ (181,840)	$ 3,376	$ 544	$ 118,901
Total Deferral and Variance Accounts		$ (349,519)	$ 128,660	$ (3,976)	$ (641)	$ (225,476)

Further to the Board Report, the Board agrees that at the time of rebasing, all DVA balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline. Accordingly, HCHI is not requesting disposition of the following DVA balances:

i. 1555 Smart Meter Capital and Recovery Offset – Sub-account – Capital;

ii. 1555 Smart Meter Capital and Recovery Offset – Sub-account – Recoveries;

iii. 1556 Smart Meter Operation, Maintenance and Administration; and

iv. 1562 Deferred Payments in Lieu of Taxes.

With respect to 1555 and 1556, the Smart Meter accounts, additional filing requirements are set out in the "*Smart Meter Funding and Cost Recovery Guideline (G-2008-002)*" ("SM Guideline") issued by the Board October 22, 2008. The SM Guideline guides distributors on managing accounting matters and making application for cost recovery. An application for smart meter cost recovery must be based on costs already expensed (i.e. not forecast) and that all cost information and related deferral account balances have been audited. As further discussed in this Exhibit under Tab 2 that follows, HCHI is authorized to install smart meters and commenced deployment on July 22, 2009 with installation expected to be completed by December 31, 2009. Although HCHI anticipates 100% installation just prior to 2010, the rate test year, HCHI does not currently meet the filing requirements to apply for smart meter cost recovery (i.e. disposition of the DVA), but is requesting a utility-specific smart meter funding adder in the interim. HCHI further requests that these smart meter variance accounts, previously authorized by the Board, shall also be continued.

By letter dated March 3, 2008, the Board advised that seven distributors that filed cost of service applications for 2008 rates had requested the disposition of account 1562, Deferred Payments in Lieu of Taxes ("Deferred PILs"). To date the Board had not reviewed the methodology or account balances for account 1562. By Notice dated

November 28, 2008, the Board initiated a combined proceeding – Board file no. EB-2008-0381 – to determine the methodology that should be used for the calculation and disposition of these balances, by determining the accuracy of the final account balances for certain of those 2008 applicants. The Board intends to proceed with the review and disposition of the account 1562 Deferred PILs balances for all distributors shortly after the completion of this proceeding.

COST ALLOCATION AND DERIVATION OF DEFERRAL AND VARIANCE ACCOUNT RATE RIDERS

The following Table 4 provides the 2010 load forecast data by customer class and the associated allocators.

Table 4
2010 Load Forecast Data and Allocators

2010 FORECAST DATA BY CLASS	kW	kWh	kWh (Non - RPP Customers)		Distribution Revenue	Number of Customers/ Connections
Residential	-	169,492,357	23,728,930	$	8,692,594	18,534
General Service < 50 kW	-	60,923,412	9,747,746	$	2,112,502	2,357
General Service 50 to 4999 kW	296,554	109,459,903	22,986,580	$	1,548,436	143
Sentinel Lights	1,167	418,928	50,271	$	74,483	589
Street Lighting	6,475	2,328,757	-	$	199,036	2,879
Unmetered Scattered Load	-	482,264	-	$	22,822	84
Total	**304,196**	**343,105,621**	**56,513,527**	**$**	**12,649,873**	**24,586**

ALLOCATORS	kW	kWh	kWh (Non - RPP Customers)	Distribution Revenue	Number of Customers/ Connections
Residential	0.00%	49.40%	41.99%	68.72%	75.38%
General Service < 50 kW	0.00%	17.76%	17.25%	16.70%	9.59%
General Service 50 to 4999 kW	97.49%	31.90%	40.67%	12.24%	0.58%
Sentinel Lights	0.38%	0.12%	0.09%	0.59%	2.40%
Street Lighting	2.13%	0.68%	0.00%	1.57%	11.71%
Unmetered Scattered Load	0.00%	0.14%	0.00%	0.18%	0.34%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

In accordance with the Board Report, the deferral and variance account balances claimed for disposition (refer to Table 3) are allocated to the customer rate classes based on the default allocation factors as approved by the Board. Also as required, a volumetric rate rider has been applied to dispose of the balances over the default disposition period of one year – with an implementation date of May 1, 2010, which is concurrent with the implementation of the distribution rate changes. The derivation of the deferral and variance account rate riders is provided in the following Table 5.

Table 5
Derivation of Deferral and Variance Account Rate Riders

DEFERRAL AND VARIANCE ACCOUNTS	Account No.	Total Claim	Allocation Factor	Residential	General Service < 50 kW	General Service 50 to 4999 kW	Sentinel Lights	Street Lighting	Unmetered Scattered Load
RSVA - Wholesale Market Service Charge	1580	$ (930,595)	kWh	$ (459,709)	$ (165,241)	$ (296,885)	$ (1,136)	$ (6,316)	$ (1,308)
RSVA - Retail Transmission Network Charge	1584	$ (29,698)	kWh	$ (14,670)	$ (5,273)	$ (9,474)	$ (36)	$ (202)	$ (42)
RSVA - Retail Transmission Connection Charge	1586	$ 152,981	kWh	$ 75,572	$ 27,164	$ 48,805	$ 187	$ 1,038	$ 215
RSVA - Power	1588	$ 222,149	kWh	$ 109,740	$ 39,446	$ 70,871	$ 271	$ 1,508	$ 312
RSVA - Power - Global Adjustment	1588	$ 240,786	kWh - Non RPP	$ 101,101	$ 41,532	$ 97,938	$ 214	$ -	$ -
Sub-Total - RSVAs		$ (344,377)		$ (187,966)	$ (62,372)	$ (88,744)	$ (500)	$ (3,972)	$ (822)
Other Regulatory Assets - Pension Contributions	1508	$ 205,783	Dist'n Revenue	$ 141,408	$ 34,365	$ 25,189	$ 1,212	$ 3,238	$ 371
Retail Cost Variance Account - Retail	1518	$ 351,891	# Customers	$ 265,271	$ 33,735	$ 2,047	$ 8,430	$ 41,206	$ 1,202
Retail Cost Variance Account - STR	1548	$ 4,845	# Customers	$ 3,652	$ 464	$ 28	$ 116	$ 567	$ 17
LV Variance Account	1550	$ (306,222)	kWh	$ (151,272)	$ (54,374)	$ (97,693)	$ (374)	$ (2,078)	$ (430)
Qualifying Transition Costs	1570	$ (530,391)	# Customers	$ (399,832)	$ (50,847)	$ (3,085)	$ (12,706)	$ (62,108)	$ (1,812)
Recovery of Regulatory Asset Balances	1590	$ 392,995	kWh	$ 194,137	$ 69,782	$ 125,376	$ 480	$ 2,667	$ 552
Sub-Total - Non RSVAs		$ 118,901		$ 53,364	$ 33,125	$ 51,862	$ (2,843)	$ (16,508)	$ (100)
TOTAL DEFERRAL AND VARIANCE ACCOUNTS TO BE RECOVERED (REFUNDED)		**$ (225,476)**		**$ (134,602)**	**$ (29,247)**	**$ (36,882)**	**$ (3,343)**	**$ (20,480)**	**$ (923)**
Disposition Period (default) - One Year									
Volumetric Rate Rider - *Billing Determinants*				***kWh***	***kWh***	***kW***	***kW***	***kW***	***kWh***
DEFERRAL AND VARIANCE ACCOUNTS RATE RIDER (Volumetric)				**$ (0.0008)**	**$ (0.0005)**	**$ (0.1244)**	**$ (2.8645)**	**$ (3.1629)**	**$ (0.0019)**

PROPOSED RATE RIDERS AND BILL IMPACTS

In total, HCHI is requesting approval to dispose of a DVA credit balance in the amount of $225,476, over the default disposition period of one year commencing May 1, 2010, applied as a rate rider to the volumetric distribution charge. This rate rider would effectively provide HCHI's distribution customers with a credit for this one year period.

The proposed rate riders that result from the disposal of the deferral and variance account balances as requested and the corresponding bill impacts are provided in the following Table 6.

Table 6
Proposed DVA Rate Riders and Bill Impacts

RATE CLASS	PROPOSED RATE RIDER		MONTHLY BILL IMPACT		
	$	Metric	Volume	Monthly Charge ($)	Total Bill Impact (%)
Residential	$(0.0008)	kWh	800 kWh	$ (0.64)	(0.53%)
General Service < 50 kW	$(0.0005)	kWh	2000 kWh	$ (1.00)	(0.38%)
General Service 50 to 4999 kW	$(0.1244)	kW	100 kW	$ (12.44)	(0.17%)
General Service 50 to 4999 kW (Interval Metered)	$(0.1244)	kW	500 kW	$ (62.20)	(0.24%)
Sentinel Lights	$(2.8645)	kW	0.21 kW	$ (0.60)	(3.29%)
Street Lighting	$(3.1629)	kW	535 kW	$ (1,692.15)	(5.04%)
Unmetered Scattered Load	$(0.0019)	kWh	500 kWh	$ (0.95)	(1.38%)

SMART METER FUNDING ADDER – BACKGROUND

On October 22, 2008 the Board issued "*Smart Meter Funding and Cost Recovery Guideline (G-2008-002)*" ("SM Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities. As set out in the SM Guideline, and as part of its 2009 IRM Application (Board File No. EB-2008-0181), Haldimand County Hydro Inc. ("HCHI") requested, and the Board approved, the standard smart meter funding adder of $1.00 per metered customer per month – which was intended to provide funding in the case where a distributor, which was authorized and clearly intended to install smart meters in the rate test year, may be in the early stages of planning and may not yet have sufficient cost information to request a utility-specific funding adder. The $1.00 per metered customer per month was intended to provide funding for HCHI's smart metering activities in the 2009 rate year. The following is an excerpt from HCHI's Manager's Summary which accompanied their 2009 IRM Application, dated November 6, 2008:

> *"…Haldimand County Hydro Inc. intends to install smart meters during the rate test year, commencing July 2009 and continuing through to the end of the year.*
>
> *a) Haldimand County Hydro Inc. is a member of the Niagara Erie Power Alliance ("NEPA") – a cooperative venture of 11 local distribution companies ("LDCs") in south eastern Ontario – who has been planning a collective and collaborative approach to their Advanced Metering Infrastructure ("AMI") procurement and installation. The NEPA group has also engaged Util-Assist to provide consulting assistance in this regard.*
>
> *b) Smart meters will be procured pursuant to and in compliance with the August 14, 2007 Request for Proposal ("RFP") issued by London Hydro Inc. A letter dated August 1, 2008, from PRP International, Inc. attests to this and accordingly determined the highest ranked AMI proponent for the NEPA group to be KTI/Sensus Limited. Please refer to 'Appendix A' for a copy of this letter.* (Note: A copy of this letter is now included as **Appendix B**.)
>
> *c) It is expected that contracts will be in place by January 2009 to purchase the AMI which meets the minimum functionality adopted in O. Reg. 425/06.*
>
> *d) It is estimated that in the order of 20,174 meters (residential plus small general service with no demand customers) will be installed.*

Total installed costs during the rate test year are estimated in the order of $3.698 million, or $183 per installed meter.

e) *It is expected that no additional costs will be incurred for associated functions for which the Smart Meter Entity ("SME") has the exclusive authority to carry out pursuant to O. Reg. 393/07. A NEPA group RFP for a temporary Operational Data Storage ("ODS") will soon be released. The ODS will assist the NEPA group with validating and auditing smart meter/AMI data until the centralized MDM/R is fully operational…"*

By letter dated June 26, 2009, the Board announced new reporting requirements related to smart meter deployment and the application of time-of-use pricing. The information required to be reported by each distributor includes: the status of the deployment of smart meters in its service area; the integration of its meters and systems with the provincial meter data management and meter data repository ("MDM/R"); and its plans for implementing TOU and billing for RPP-eligible consumers. HCHI's baseline filing, dated July 9, 2009, reported the following status update as of July 1, 2009:

- An agreement with Sensus Metering Systems Inc., an advanced metering infrastructure ("AMI") vendor was completed and being signed to acquire 100% of the smart meters required. A letter dated August 15, 2009 from PRP International, Inc. provides further confirmation of the Fairness Commissioner for the negotiations and contracting phase and HCHI's administration of the contract awarded to its #1 ranked Proponent, KTI/Sensus Limited – a copy of this letter is also included in **Appendix B**;
- Mass installation to begin July 22, 2009 and targeted completion date of December 31, 2009;
- Installation of AMI systems and structures had begun, including the advanced metering control computer ("AMCC") and advanced metering regional collector ("AMRC");

- Integration of meters and systems with the MDM/R had not begun and the planned start date is January 1, 2010 with the planned completion date of December 31, 2010; and
- Changes to business processes and systems related to the MDM/R and TOU had not begun and the planned start date is October 5, 2009 with the planned completion date of March 31, 2010.

Each of the following Tables 7, 8, 9 and 10 provide the information required to be reported in "Appendix 2-S Smart Meters" per the Board's "*Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*" issued May 27, 2009.

The following Table 7 sets out HCHI's smart meter plan, also as filed with the July 9, 2009 baseline report to the Board, which includes the number of meters proposed to be installed and an installation schedule for each month during mass deployment.

Table 7
Actual and Planned Smart Meter Implementations as of July 1, 2009

Month	Residential Meters Installed	General Service < 50 kW Meters Installed	TOTAL Meters Installed
April 2009	12	8	**20**
May 2009	2	1	**3**
June 2009	22	9	**31**
July 2009	1,519	392	**1,911**
August 2009	4,556	392	**4,948**
September 2009	4,556	392	**4,948**
October 2009	3,038	392	**3,430**
November 2009	3,038	392	**3,430**
December 2009	1,482	376	**1,858**
TOTAL	**18,225**	**2,354**	**20,579**

SMART METER CAPITAL EXPENDITURES AND OM&A COSTS

The following Table 8 summarizes the 2007 and 2008 Actual, and the 2009 and 2010 Forecast Capital Expenditures for smart meters.

Table 8
Capital Expenditures

	2007 Actual (Audited)	2008 Actual (Audited)	2009 Forecast	2010 Forecast	Total
Advanced Metering Communication Device (AMCD)					
Smart Meters	$ -	$ -	$ 2,119,396	$ 32,189	$ 2,151,585
Installation	$ -	$ -	$ 633,193	$ -	$ 633,193
Workforce Automation Hardware	$ -	$ -	$ 7,500	$ -	$ 7,500
	$ -	$ -	$ 2,760,088	$ 32,189	$ 2,792,277
Advanced Metering Regional Collector (AMRC)					
Collectors	$ -	$ -	$ 545,330	$ -	$ 545,330
Installation	$ -	$ -	$ 176,759	$ 3,150	$ 179,909
	$ -	$ -	$ 722,089	$ 3,150	$ 725,239
Advanced Metering Control Computer (AMCC)					
Customer Information System Automated Meter Change	$ -	$ -	$ 26,519	$ -	$ 26,519
	$ -	$ -	$ 26,519	$ -	$ 26,519
Other AMI Capital Costs (minimum functionality)					
AMI Interface to Customer Information System	$ -	$ -	$ 31,500	$ 10,500	$ 42,000
Professional Fees	$ 14,289	$ 14,916	$ 56,700	$ 21,000	$ 106,905
Customer Presentment Tools & Bill Print Modifications	$ -	$ -	$ 53,038	$ 10,500	$ 63,538
Labour and Benefits	$ 76,276	$ 25,415	$ -	$ -	$ 101,691
	$ 90,565	$ 40,331	$ 141,238	$ 42,000	$ 314,134
Total Capital Expenditures	**$ 90,565**	**$ 40,331**	**$ 3,649,933**	**$ 77,339**	**$ 3,858,169**
				Actual / Planned Meter Installations	**20,579**
				Total Capital Expenditures per Meter	**$ 187.48**

The following Table 9 summarizes the 2009 and 2010 Forecast incremental OM&A costs for smart meters.

Table 9
Incremental OM&A Costs

	2009 Forecast	2010 Forecast	Total
Advanced Metering Communication Device (AMCD)			
Maintenance	$ 276,198	$ 272,721	$ 548,919
	$ 276,198	$ 272,721	$ 548,919
Advanced Metering Regional Collector (AMRC)			
Maintenance	$ 3,780	$ 3,875	$ 7,655
	$ 3,780	$ 3,875	$ 7,655
Advanced Metering Control Computer (AMCC)			
Maintenance	$ -	$ 21,000	$ 21,000
	$ -	$ 21,000	$ 21,000
Other AMI OM&A Costs (minimum functionality)			
Customer Communication / Education Packages	$ 43,588	$ 52,305	$ 95,893
Staff Training and Department Integration	$ -	$ 15,750	$ 15,750
Temporary Staff Labour and Benefits	$ 37,030	$ 30,940	$ 67,970
Smart Meter Entity / MDM/R (Temporary ODS)	$ 91,534	$ 92,524	$ 184,058
	$ 172,152	$ 191,519	$ 363,671
	$ 452,129	**$ 489,115**	**$ 941,244**
Actual / Planned Meter Installations			**20,579**
Total OM&A Costs per Meter			**$ 45.74**

Stranded meter costs were addressed by the Board in its Decision with Reasons, issued on August 8, 2007, in the combined proceeding in relation to smart meter costs for the thirteen distributors that were authorized by regulation at that time to conduct smart meter activities – Board file no. EB-2007-0063 ("Combined Proceeding"). The Board accepted that stranded cost associated with existing meters should stay in rate base and to continue to track the costs associated with stranded meters. HCHI has therefore not included the costs of stranded meters in the calculation of its smart meter revenue requirement, and will continue to include stranded meters in rate base.

SMART METER FUNDING ADDER – UTILITY SPECIFIC

The Board expects that a distributor will normally file for inclusion of smart meter costs into ongoing operations and rate base when it files for a cost of service rate adjustment. However, in accordance with the SM Guideline, an application for smart meter cost recovery must be based on costs already expensed (i.e. not forecast) and that all cost information and related deferral account balances have been audited. Although HCHI anticipates 100% installation just prior to 2010, the rate test year, HCHI does not currently meet the filing requirements to apply for smart meter cost recovery but is requesting a utility-specific smart meter funding adder, in the interim, to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board.

HCHI has calculated the smart meter revenue requirement based on the actual capital expenditures to the end of 2008 and forecasted capital expenditures and incremental OM&A costs for 2009 and 2010. The smart meter revenue requirement, for each of the years 2007 to 2010 inclusive, was calculated in the manner set out in the Combined Proceeding and is summarized in Table 10 below. The annual detailed calculations are provided in **Appendix C**.

The smart meter revenue requirement is reduced by the amounts previously collected in funding adders and forecast to be collected, including carrying charges, to the proposed implementation date of May 1, 2010, which is concurrent with the implementation of the distribution rate changes.

The net revenue requirement has been allocated to all metered customers as forecast for 2010 over a recovery period of 48 months; that is, to April 30, 2014.

Table 10
Summary of Smart Meter Revenue Requirement and Smart Meter Funding Adder

Revenue Requirement for Smart Meters Installed	
2006 Rate Year Entitlement	$ -
2007 Rate Year Entitlement	$ 7,370
2008 Rate Year Entitlement	$ 288,063
2009 Rate Year Entitlement	$ 1,016,699
2010 Rate Year Entitlement	$ 1,027,715
	$ 2,339,847
Smart Meter Funding Adder Collected in Rates	
2006 Rate Year Collected - May 1/06 to April 30/07	$ (59,041)
2007 Rate Year Collected - May 1/07 to April 30/08	$ (68,338)
2008 Rate Year Collected - May 1/08 to April 30/09	$ (69,446)
2009 Rate Year Forecasted - May 1/09 to April 30/10	$ (253,075)
	$ (449,899)
Revenue Requirement for Recovery	**$ 1,889,948**
Number of Metered Customers (per 2010 Forecast)	21,034
Number of Months (May 1/10 to April 30/14)	48
Funding Adder per Metered Customer per Month	**$ 1.87**

HCHI is requesting a Smart Meter Funding Adder of $1.87 per metered customer per month.

Since HCHI is not applying for the recovery of smart meter costs, HCHI will continue to track costs in the smart meter variance accounts 1555 and 1556 previously authorized by the Board, and as such is not proposing to dispose of these variance accounts at this time.

APPENDIX A

DEFERRAL AND VARIANCE ACCOUNTS CONTINUITY SCHEDULE

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

Account Description	Account Number	2005 Opening Principal Amounts as of Jan-1-05 [1]	2005 Transactions - Net Additions (Reductions) during 2005, excluding interest and adjustments [6]	2005 Adjustments during 2005 - instructed by Board [2]	2005 Adjustments during 2005 - other [3]	2005 Closing Principal Balance as of Dec-31-05	2005 Opening Interest Amounts as of Jan-1-05	2005 Interest Jan-1 to Dec31-05	2005 Closing Interest Amounts as of Dec-31-05	2006 Opening Principal Amounts as of Jan-1-06	2006 Transactions - Net Additions (Reductions) during 2006, excluding interest and adjustments [6]	2006 Adjustments during 2006 - instructed by Board [2]	2006 Adjustments during 2006 - other [3]	2006 Transfer of Board-approved amounts to 1590 as per 2006 EDR	2006 Closing Principal Balance as of Dec-31-06	2006 Opening Interest Amounts as of Jan-1-06	2006 Interest Jan-1 to Dec31-06	2006 Transfer of Board-approved amounts to 1590 as per 2006 EDR	2006 Closing Interest Amounts as of Dec-31-06
RSVA - Wholesale Market Service Charge	1580	$ 600,439	$ 258,047			$ 858,486	$ 102,527	$ 54,186	$ 156,712	$ 858,486	$ (476,442)			$ (600,439)	$ (218,395)	$ 156,712	$ 19,171	$ (160,569)	$ 15,314
RSVA - Retail Transmission Network Charge	1584	$ (422,428)	$ (225,442)			$ (647,870)	$ (10,099)	$ (40,753)	$ (50,852)	$ (647,870)	$ 74,020			$ 422,428	$ (151,422)	$ (50,852)	$ (24,829)	$ 50,933	$ (24,748)
RSVA - Retail Transmission Connection Charge	1586	$ (527,589)	$ (222,361)			$ (749,950)	$ (29,376)	$ (46,296)	$ (75,672)	$ (749,950)	$ 129,160			$ 527,589	$ (93,201)	$ (75,672)	$ (25,979)	$ 80,377	$ (21,275)
Sub-Total - RSVAs (excluding Power)		$ (349,578)	$ (189,756)	$ -	$ -	$ (539,334)	$ 63,052	$ (32,864)	$ 30,188	$ (539,334)	$ (273,262)	$ -	$ -	$ 349,578	$ (463,018)	$ 30,188	$ (31,638)	$ (29,259)	$ (30,709)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ 134,689			$ 134,689	$ -	$ 2,301	$ 2,301	$ 134,689	$ 43,638				$ 178,327	$ 2,301	$ 7,272		$ 9,573
Retail Cost Variance Account - Retail	1518	$ 192,569	$ 77,286			$ 269,855	$ 10,799	$ 21,643	$ 32,442	$ 269,855	$ 85,288			$ (192,569)	$ 162,573	$ 32,442	$ 10,760	$ (29,414)	$ 13,788
Retail Cost Variance Account - STR	1548	$ 12,370	$ 1,671			$ 14,041	$ 798	$ 1,583	$ 2,381	$ 14,041	$ 475			$ (12,370)	$ 2,146	$ 2,381	$ 400	$ (1,994)	$ 788
Misc. Deferred Debits	1525	$ 53,255	$ (0)			$ 53,255	$ 7,722	$ 3,861	$ 11,583	$ 53,255	$ -			$ (53,255)	$ -	$ 11,583	$ 1,287	$ (12,870)	$ 0
LV Variance Account	1550	$ -				$ -	$ -	$ -	$ -	$ -	$ (165,728)				$ (165,728)	$ -	$ (433)		$ (433)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -				$ -	$ -	$ -	$ -	$ -	$ -				$ -	$ -	$ (421)		$ (421)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -				$ -	$ -	$ -	$ -	$ -	$ (36,618)				$ (36,618)	$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ -				$ -	$ -	$ -	$ -	$ -	$ -				$ -	$ -	$ -		$ -
Qualifying Transition Costs [5]	1570	$ 640,794	n/a	$ (104,816)	$ (1,487)	$ 534,491	$ 184,396	$ 17,868	$ 202,264	$ 534,491	n/a		$ (1,150)	$ (940,724)	$ (407,383)	$ 202,264	$ (27,385)	$ (257,079)	$ (82,200)
Pre-Market Opening Energy Variances Total [5]	1571	$ 592,797	n/a			$ 592,797	$ 90,810	$ 42,978	$ 133,788	$ 592,797	n/a			$ (592,797)	$ (0)	$ 133,788	$ 14,326	$ (148,114)	$ (0)
Sub-Total - Non RSVAs		$ 1,491,785	$ 213,645	$ (104,816)	$ (1,487)	$ 1,599,127	$ 294,525	$ 90,234	$ 384,759	$ 1,599,127	$ (72,945)	$ -	$ (1,150)	$ (1,791,714)	$ (266,682)	$ 384,759	$ 5,806	$ (449,470)	$ (58,905)
Deferred Payments in Lieu of Taxes	1562	$ 439,765	$ 497,849			$ 937,614	$ 16,194	$ 93,108	$ 109,302	$ 937,614	$ (173,611)				$ 764,003	$ 109,302	$ 45,994		$ 155,296
2006 PILs & Taxes Variance	1592	$ -				$ -	$ -		$ -	$ -	$ -				$ -	$ -	$ -		$ -
Sub-Total - PILs		$ 439,765	$ 497,849	$ -	$ -	$ 937,614	$ 16,194	$ 93,108	$ 109,302	$ 937,614	$ (173,611)	$ -	$ -	$ -	$ 764,003	$ 109,302	$ 45,994	$ -	$ 155,296
RSVA - Power ("excluding" Global Adjustment)	1588	$ (666,358)	$ (107,012)			$ (773,370)	$ (404,338)	$ 391,285	$ (13,053)	$ (773,370)	$ (457,747)			$ 666,358	$ (564,760)	$ (13,053)	$ (38,550)	$ 468,753	$ 417,149
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ 50,018			$ 50,018	$ -	$ (751)	$ (751)	$ 50,018	$ 41,720				$ 91,739	$ (751)	$ 10,325		$ 9,575
Sub-Total - RSVA - Power (including GA)		$ (666,358)	$ (56,994)	$ -	$ -	$ (723,352)	$ (404,338)	$ 390,534	$ (13,804)	$ (723,352)	$ (416,027)	$ -	$ -	$ 666,358	$ (473,021)	$ (13,804)	$ (28,225)	$ 468,753	$ 426,724
Recovery of Regulatory Asset Balances	1590	$ (577,734)	$ (659,694)			$ (1,237,427)	$ (11,738)	$ (68,061)	$ (79,799)	$ (1,237,427)	$ 132,228			$ 775,778	$ (329,421)	$ (79,799)	$ (47,579)	$ 9,976	$ (117,402)
Sub-Total - RAR 1590		$ (577,734)	$ (659,694)	$ -	$ -	$ (1,237,427)	$ (11,738)	$ (68,061)	$ (79,799)	$ (1,237,427)	$ 132,228	$ -	$ -	$ 775,778	$ (329,421)	$ (79,799)	$ (47,579)	$ 9,976	$ (117,402)
TOTAL - ALL ACCOUNTS		$ 337,880	$ (194,949)	$ (104,816)	$ (1,487)	$ 36,628	$ (42,306)	$ 472,951	$ 430,645	$ 36,628	$ (803,617)	$ -	$ (1,150)	$ -	$ (768,138)	$ 430,645	$ (55,642)	$ (0)	$ 375,003

APPENDIX A

DEFERRAL AND VARIANCE ACCOUNTS CONTINUITY SCHEDULE

Account Description	Account Number	2007 Opening Principal Amounts as of Jan-1-07	2007 Transactions - Net Additions (Reductions) during 2007, excluding interest and adjustments [6]	2007 Adjustments during 2007 - instructed by Board [2]	2007 Adjustments during 2007 - other [3]	2007 Closing Principal Balance as of Dec-31-07	2007 Opening Interest Amounts as of Jan-1-07	2007 Interest Jan-1 to Dec31-07	2007 Closing Interest Amounts as of Dec-31-07	2008 Opening Principal Amounts as of Jan-1-08	2008 Transactions - Net Additions (Reductions) during 2008, excluding interest and adjustments [6]	2008 Adjustments during 2008 - instructed by Board [2]	2008 Adjustments during 2008 - other [3]	2008 Closing Principal Balance as of Dec-31-08	2008 Opening Interest Amounts as of Jan-1-08	2008 Interest Jan-1 to Dec31-08	2008 Closing Interest Amounts as of Dec-31-08	Projected Interest on Dec 31 -08 balance from Jan 1, 2009 to Dec 31, 2009 [9]	Projected Interest on Dec 31 -08 balance from Jan 1, 2010 to April 30, 2010 [9]	Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (218,395)	$ (448,697)			$ (667,092)	$ 15,314	$ (20,307)	$ (4,993)	$ (667,092)	$ (216,605)			$ (883,697)	$ (4,993)	$ (30,233)	$ (35,226)	$ (10,052)	$ (1,620)	$ (930,595)
RSVA - Retail Transmission Network Charge	1584	$ (151,422)	$ 159,889			$ 8,467	$ (24,748)	$ (2,915)	$ (27,663)	$ 8,467	$ (9,895)			$ (1,428)	$ (27,663)	$ (587)	$ (28,251)	$ (16)	$ (3)	$ (29,698)
RSVA - Retail Transmission Connection Charge	1586	$ (93,201)	$ 194,224			$ 101,023	$ (21,275)	$ (926)	$ (22,202)	$ 101,023	$ 66,813			$ 167,836	$ (22,202)	$ 5,130	$ (17,071)	$ 1,909	$ 308	$ 152,981
Sub-Total - RSVAs (excluding Power)		$ (463,018)	$ (94,584)	$ -	$ -	$ (557,602)	$ (30,709)	$ (24,149)	$ (54,858)	$ (557,602)	$ (159,687)	$ -	$ -	$ (717,290)	$ (54,858)	$ (25,690)	$ (80,548)	$ (8,159)	$ (1,315)	$ (807,312)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 178,327	$ -			$ 178,327	$ 9,573	$ 8,430	$ 18,003	$ 178,327	$ -			$ 178,327	$ 18,003	$ 7,097	$ 25,100	$ 2,028	$ 327	$ 205,783
Retail Cost Variance Account - Retail	1518	$ 162,573	$ 85,360			$ 247,933	$ 13,788	$ 9,609	$ 23,397	$ 247,933	$ 65,345			$ 313,279	$ 23,397	$ 11,078	$ 34,474	$ 3,564	$ 574	$ 351,891
Retail Cost Variance Account - STR	1548	$ 2,146	$ 344			$ 2,489	$ 788	$ 104	$ 892	$ 2,489	$ 1,291			$ 3,781	$ 892	$ 122	$ 1,015	$ 43	$ 7	$ 4,845
Misc. Deferred Debits	1525	$ -	$ -			$ -	$ 0	$ -	$ 0	$ -	$ -			$ -	$ 0	$ -	$ 0	$ -	$ -	$ 0
LV Variance Account	1550	$ (165,728)	$ (91,555)			$ (257,283)	$ (433)	$ (10,410)	$ (10,843)	$ (257,283)	$ (23,594)			$ (280,877)	$ (10,843)	$ (10,792)	$ (21,635)	$ (3,195)	$ (515)	$ (306,222)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ 90,565			$ 90,565	$ (421)	$ (1,765)	$ (2,186)	$ 90,565	$ 40,331			$ 130,896	$ (2,186)	$ (772)	$ (2,958)	$ (387)	$ (62)	$ 127,489
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (36,618)	$ (64,029)			$ (100,647)	$ -	$ -	$ -	$ (100,647)	$ (64,248)			$ (164,894)	$ -	$ -	$ -	$ -	$ -	$ (164,894)
Smart Meter OM&A Variance	1556	$ -	$ -			$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ (407,383)	n/a		$ 41	$ (407,342)	$ (82,200)	$ (19,257)	$ (101,457)	$ (407,342)	n/a			$ (407,342)	$ (101,457)	$ (16,212)	$ (117,669)	$ (4,634)	$ (747)	$ (530,391)
Pre-Market Opening Energy Variances Total [5]	1571	$ (0)	n/a			$ (0)	$ (0)	$ -	$ (0)	$ (0)	n/a			$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)	$ (0)
Sub-Total - Non RSVAs		$ (266,682)	$ 20,684	$ -	$ 41	$ (245,957)	$ (58,905)	$ (13,288)	$ (72,194)	$ (245,957)	$ 19,125	$ -	$ -	$ (226,831)	$ (72,194)	$ (9,479)	$ (81,672)	$ (2,580)	$ (416)	$ (311,499)
Deferred Payments in Lieu of Taxes	1562	$ 764,003	$ 137			$ 764,140	$ 155,296	$ 36,127	$ 191,422	$ 764,140	$ (89)			$ 764,050	$ 191,422	$ 30,411	$ 221,833	$ 8,691	$ 1,401	$ 995,976
2006 PILs & Taxes Variance	1592	$ -	$ -			$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total - PILs		$ 764,003	$ 137	$ -	$ -	$ 764,140	$ 155,296	$ 36,127	$ 191,422	$ 764,140	$ (89)	$ -	$ -	$ 764,050	$ 191,422	$ 30,411	$ 221,833	$ 8,691	$ 1,401	$ 995,976
RSVA - Power ("excluding" Global Adjustment)	1588	$ (564,760)	$ 233,438			$ (331,322)	$ 417,149	$ (38,379)	$ 378,771	$ (331,322)	$ 188,121			$ (143,201)	$ 378,771	$ (11,529)	$ 367,241	$ (1,629)	$ (263)	$ 222,149
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 91,739	$ (49,804)			$ 41,935	$ 9,575	$ 11,610	$ 21,185	$ 41,935	$ 172,216			$ 214,151	$ 21,185	$ 2,621	$ 23,806	$ 2,436	$ 393	$ 240,786
Sub-Total - RSVA - Power (including GA)		$ (473,021)	$ 183,635	$ -	$ -	$ (289,386)	$ 426,724	$ (26,769)	$ 399,955	$ (289,386)	$ 360,336	$ -	$ -	$ 70,950	$ 399,955	$ (8,908)	$ 391,047	$ 807	$ 130	$ 462,934
Recovery of Regulatory Asset Balances	1590	$ (329,421)	$ 582,585			$ 253,165	$ (117,402)	$ (2,311)	$ (119,713)	$ 253,165	$ 236,488			$ 489,653	$ (119,713)	$ 16,588	$ (103,125)	$ 5,570	$ 898	$ 392,995
Sub-Total - RAR 1590		$ (329,421)	$ 582,585	$ -	$ -	$ 253,165	$ (117,402)	$ (2,311)	$ (119,713)	$ 253,165	$ 236,488	$ -	$ -	$ 489,653	$ (119,713)	$ 16,588	$ (103,125)	$ 5,570	$ 898	$ 392,995
TOTAL - ALL ACCOUNTS		$ (768,138)	$ 692,457	$ -	$ 41	$ (75,640)	$ 375,003	$ (30,390)	$ 344,613	$ (75,640)	$ 456,173	$ -	$ -	$ 380,532	$ 344,613	$ 2,922	$ 347,535	$ 4,329	$ 698	$ 733,094

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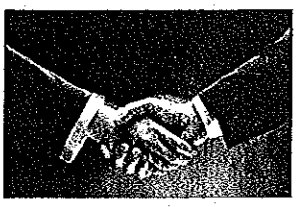

PRP International, Inc.

Fairness Advisory Services

August 1, 2008

Mr. Lloyd Payne
President & CEO
Haldimand County Hydro Inc.
1 Greendale Drive
Caledonia, ON N3W 2J3

Dear Mr. Payne:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August-July 2008
London Hydro, Consortium & Add-On LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Add-On LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the ***NEPA Collective of LDCs (Brant County Power Inc., Brantford Power Inc., Canadian Niagara Power Inc. (Fortis), Grimsby Power Incorporated, Haldimand County Hydro Inc., Niagara-on-the-Lake Hydro Inc., Niagara Peninsula Energy Inc., Norfolk Power Distribution Inc., and Welland Hydro Electric System Corp.)*** *requirements are:*

- *KTI/Sensus Limited, as the recommended Preferred Proponent, based on its highest ranking, and*
- *Elster Metering being the second ranked Proponent.*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen
President
cc: Mr. Gary Rains, RFP Project Director

203 - 8 QUEEN STREET, SUMMERSIDE, PEI C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

9s.

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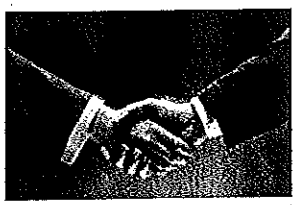

PRP International, Inc.

Fairness Advisory Services

August 15, 2009

Mr. Lloyd Payne
President & CEO
Haldimand County Hydro Inc.
1 Greendale Drive
Caledonia, ON N3W 2J3

Dear Mr. Payne:

Subject: Confirmation of the Fairness Commissioner
Haldimand County Hydro Inc.
– KTI/Sensus Limited Contract Award
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its Confirming Letter of the Fairness Commissioner for the noted negotiations and contracting phase of the LH AMI Request for Proposal (RFP) procurement. This judgment is being provided for the information and use of Haldimand County Hydro Inc. ("HCHI"), in its administration of the contract awarded to its #1 ranked Proponent, KTI/Sensus Limited.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner engaged by HCHI *for the phase of negotiations and contract award pursuant to the Fairness Protocols issued August 2008, that the successful conclusion of negotiations and contract between* Haldimand County Hydro Inc. *and* KTI/Sensus Limited, *were undertaken in accordance with the principle for such negotiations and contract award set out in the RFP, issued August 14, 2007."*

A backgrounder and summary of the Fairness Protocols is attached and forms part of this Confirming Letter.

Yours truly,

Peter Sorensen

Peter Sorensen
President

Attachment: Negotiations and Contract Phase Backgrounder

203 - 8 Queen Street, Summerside, PEI C1N 0A6
Direct telephone: 902.436.3930 Fax: 604-677-5409
Email: fairness@telus.net

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

TO WHOM IT MAY CONCERN:

Background:

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;
- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;
- RFP Provision 7.5.14[1] provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and
- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

Fairness Coverage Objective:

Normally, fairness coverage terminates with the determination of the ranked Proponents following the evaluation and selection phase of the RFP; however, certain LDCs expressed a wish to secure additional fairness coverage during the subsequent phase of negotiations and contract award. The objective for this second phase fairness coverage is to assure that LDCs undertook a phase of negotiations and contracting that meets the RFP provisions of consecutive negotiations where required, e.g. with their top two ranked Proponents and in the event of unsuccessful negotiations with the #1 ranked Proponent, a subsequent contract award to the next ranked Proponent would be on an equitable basis as was the requirements in the negotiations with the #1 ranked Proponent.

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[1] 7.5.14 Final Contract Negotiations

Any conditions and provisions that a bidder seeks shall be a part of this proposal. Notwithstanding, nothing herein shall be interpreted to prohibit London Hydro from introducing or modifying contract terms and conditions during negotiation of the final contract.

London Hydro has scheduled no more than two weeks for contract negotiations (if necessary), and expects the successful bidder to maintain a prompt and responsive negotiation to accomplish and complete final contract agreement within that time period. If contract negotiations exceed an interval acceptable to London Hydro, London Hydro retains the option to terminate negotiations and continue to the next apparent successful bidder, at the sole discretion of London Hydro. Said interval shall in no event be less than three weeks.

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

Fairness Protocols:

- A Fairness Protocol was developed and issued to all LDCs, in August 2008 that set forth the best practices for fair consecutive-based negotiations and contract award.
    - The fundamental principle of the Protocol was the requirement for the LDC to establish the negotiations agenda for their top ranked Proponents and submit a copy to the Fairness Commissioner prior to engagement of their #1 ranked Proponent, i.e. the agenda would demonstrate a common statement of work, a LDC standard for pass/fail in their negotiations and the negotiation issues would only differ to the extent of the respective Proponent's technical solution being offered.

Form of Fairness Confirmation / Attestation[2]:

1. A confirmation of fair negotiations and contract award would be issued if the LDC's #1 ranked Proponent was awarded a contract; the original Attestation Letter remains in effect.

2. An Attestation of fair negotiations and contract award would be issued if the LDC determined that their #1 Proponent was to be set aside and the LDC successfully contracted with their next ranked Proponent, e.g. their #2; the original Attestation Letter is thus superseded by the Negotiations and Contract Award Attestation Letter.

Local Distribution Company:

Haldimand County Hydro Inc.

Mr. Lloyd Payne
President & CEO
Haldimand County Hydro Inc.
1 Greendale Drive
Caledonia, ON N3W 2J3

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[2] **Conditions on the rendering of this Confirmation / Attestation.**

- The two Negotiations Agenda were provided by HCHI, via its agent Util-Assist;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between HCHI and their #1 ranked Proponent;
- The successful contract award was based on the HCHI criteria and no independent analysis nor any comparison with the evaluation results of the RFP process was carried out by the Fairness Commissioner; and
- The confirmation of the Fairness Commissioner was based on the progress report(s) provided by HCHI, via its agent Util-Assist.

SMART METER REVENUE REQUIREMENT CALCULATION

Average Fixed Asset Values	2006 Audited Actual		2007 Audited Actual		2008 Audited Actual		2009 Forecasted		2010 Forecasted	
Net Fixed Assets Smart Meters	$ -		$ 43,773		$ 1,791,360		$ 3,401,672		$ 3,202,643	
Net Fixed Assets Computer Hardware	$ -		$ -		$ 3,375		$ 6,000		$ 4,500	
Net Fixed Assets Computer Software	$ -		$ -		$ 49,975		$ 98,295		$ 83,434	
Total Net Fixed Assets	$ -	$ -	$ 43,773	$ 43,773	$ 1,844,710	$ 1,844,710	$ 3,505,967	$ 3,505,967	$ 3,290,576	$ 3,290,576
Working Capital										
Operation Expense	$ -		$ -		$ -		$ 452,129		$ 489,115	
Working Capital %	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,819	$ 67,819	$ 73,367	$ 73,367
Smart Meters included in Rate Base		$ -		$ 43,773		$ 1,844,710		$ 3,573,787		$ 3,363,944
Return on Rate Base										
Deemed Short Term Debt %					0.0%		0.0%		4.0%	
Deemed Long Term Debt %	50.0%	$ -	50.0%	$ 21,887	53.3%	$ 983,230	56.7%	$ 2,026,337	56.0%	$ 1,883,808
Deemed Equity %	50.0%	$ -	50.0%	$ 21,887	46.7%	$ 861,480	43.3%	$ 1,547,450	40.0%	$ 1,345,577
		$ -		$ 43,773		$ 1,844,710		$ 3,573,787		$ 3,229,386
Weighted Debt Rate	6.1%	$ -	6.5%	$ 1,412	6.4%	$ 63,123	5.9%	$ 119,149	5.6%	$ 105,117
Proposed ROE	9.0%	$ -	9.0%	$ 1,970	9.0%	$ 77,533	9.0%	$ 139,270	8.0%	$ 107,781
Return on Rate Base		$ -	$ -	$ 3,381	$ 3,381	$ 140,657	$ 140,657	$ 258,419	$ 258,419	$ 212,897	$ 212,897
Operating Expenses										
Incremental Operating Expenses			$ -		$ -		$ -		$ 452,129		$ 489,115
Amortization Expenses										
Amortization Expenses - Smart Meters		$ -		$ 3,019		$ 123,750		$ 243,341		$ 246,397
Amortization Expenses - Computer Hardware		$ -		$ -		$ 750		$ 1,500		$ 1,500
Amortization Expenses - Computer Software		$ -		$ -		$ 11,106		$ 24,311		$ 26,411
Total Amortization Expenses			$ -		$ 3,019		$ 135,606		$ 269,152		$ 274,308
Revenue Requirement Before PILs			$ -		$ 6,400		$ 276,262		$ 979,700		$ 976,320
Calculation of Taxable Income										
Incremental Operating Expenses			$ -		$ -		$ -		$ (452,129)		$ (489,115)
Depreciation Expenses			$ -		$ (3,019)		$ (135,606)		$ (269,152)		$ (274,308)
Interest Expense			$ -		$ (1,412)		$ (63,123)		$ (119,149)		$ (105,117)
Taxable Income For PILs			$ -		$ 1,970		$ 77,533		$ 139,270		$ 107,781
Grossed up PILs			$ -		$ 969		$ 11,801		$ 36,999		$ 51,395
Revenue Requirement Before PILs			$ -		$ 6,400		$ 276,262		$ 979,700		$ 976,320
Grossed up PILs			$ -		$ 969		$ 11,801		$ 36,999		$ 51,395
Revenue Requirement for Smart Meters			**$ -**		**$ 7,370**		**$ 288,063**		**$ 1,016,699**		**$ 1,027,715**

SMART METER REVENUE REQUIREMENT
PILs CALCULATION

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
INCOME TAX					
Net Income	$ -	$ 1,970	$ 77,533	$ 139,270	$ 107,781
Amortization	$ -	$ 3,019	$ 135,606	$ 269,152	$ 274,308
CCA - Smart Meters	$ -	$ (3,623)	$ (148,210)	$ (279,862)	$ (261,140)
CCA - Computer Hardware	$ -	$ -	$ (2,063)	$ (2,991)	$ (1,346)
CCA - Computer Software	$ -	$ -	$ (55,528)	$ (66,028)	$ (10,500)
Change in taxable income	$ -	$ 1,366	$ 7,338	$ 59,541	$ 109,103
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%
Income Taxes Payable	$ -	$ 493	$ 2,458	$ 19,649	$ 33,822
ONTARIO CAPITAL TAX					
Smart Meters	$ -	$ 87,546	$ 3,495,173	$ 3,308,171	$ 3,097,114
Computer Hardware	$ -	$ -	$ 6,750	$ 5,250	$ 3,750
Computer Software	$ -	$ -	$ 99,951	$ 96,639	$ 70,228
Rate Base	$ -	$ 87,546	$ 3,601,874	$ 3,410,061	$ 3,171,092
Less: Exemption	$ -	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ -	$ 87,546	$ 3,601,874	$ 3,410,061	$ 3,171,092
Ontario Capital Tax Rate	0.300%	0.225%	0.225%	0.225%	0.075%
Net Amount (Taxable Capital x Rate)	$ -	$ 197	$ 8,104	$ 7,673	$ 2,378
Gross Up					
	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ -	$ 493	$ 2,458	$ 19,649	$ 33,822
Change in OCT	$ -	$ 197	$ 8,104	$ 7,673	$ 2,378
PIL's	$ -	$ 690	$ 10,562	$ 27,321	$ 36,200
	Gross Up 36.12%	Gross Up 36.12%	Gross Up 33.50%	Gross Up 33.00%	Gross Up 31.00%
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ -	$ 772	$ 3,697	$ 29,326	$ 49,017
Change in OCT	$ -	$ 197	$ 8,104	$ 7,673	$ 2,378
PIL's	**$ -**	**$ 969**	**$ 11,801**	**$ 36,999**	**$ 51,395**

SMART METER REVENUE REQUIREMENT
FIXED ASSET CONTINUITY SCHEDULE

FOR ACCOUNTING

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Smart Meters					
Opening Capital Investment	$ -	$ -	$ 90,565	$ 3,621,942	$ 3,678,281
Capital Investment	$ -	$ 90,565	$ 3,531,377	$ 56,339	$ 35,339
Closing Capital Investment	$ -	$ 90,565	$ 3,621,942	$ 3,678,281	$ 3,713,620
Opening Accumulated Amortization	$ -	$ -	$ 3,019	$ 126,769	$ 370,110
Amortization (15 Years Straight Line)	$ -	$ 3,019	$ 123,750	$ 243,341	$ 246,397
Closing Accumulated Amortization	$ -	$ 3,019	$ 126,769	$ 370,110	$ 616,507
Opening Net Fixed Assets	$ -	$ -	$ 87,546	$ 3,495,173	$ 3,308,171
Closing Net Fixed Assets	$ -	$ 87,546	$ 3,495,173	$ 3,308,171	$ 3,097,114
Average Net Fixed Assets	$ -	$ 43,773	$ 1,791,360	$ 3,401,672	$ 3,202,643
Computer Hardware					
Opening Capital Investment	$ -	$ -	$ -	$ 7,500	$ 7,500
Capital Investment	$ -	$ -	$ 7,500	$ -	$ -
Closing Capital Investment	$ -	$ -	$ 7,500	$ 7,500	$ 7,500
Opening Accumulated Amortization	$ -	$ -	$ -	$ 750	$ 2,250
Amortization (5 Years Straight Line)	$ -	$ -	$ 750	$ 1,500	$ 1,500
Closing Accumulated Amortization	$ -	$ -	$ 750	$ 2,250	$ 3,750
Opening Net Fixed Assets	$ -	$ -	$ -	$ 6,750	$ 5,250
Closing Net Fixed Assets	$ -	$ -	$ 6,750	$ 5,250	$ 3,750
Average Net Fixed Assets	$ -	$ -	$ 3,375	$ 6,000	$ 4,500
Computer Software					
Opening Capital Investment	$ -	$ -	$ -	$ 111,056	$ 132,056
Capital Investment	$ -	$ -	$ 111,056	$ 21,000	$ -
Closing Capital Investment	$ -	$ -	$ 111,056	$ 132,056	$ 132,056
Opening Accumulated Amortization	$ -	$ -	$ -	$ 11,106	$ 35,417
Amortization Year 1 (5 Years Straight Line)	$ -	$ -	$ 11,106	$ 24,311	$ 26,411
Closing Accumulated Amortization	$ -	$ -	$ 11,106	$ 35,417	$ 61,828
Opening Net Fixed Assets	$ -	$ -	$ -	$ 99,951	$ 96,639
Closing Net Fixed Assets	$ -	$ -	$ 99,951	$ 96,639	$ 70,228
Average Net Fixed Assets	$ -	$ -	$ 49,975	$ 98,295	$ 83,434

SMART METER REVENUE REQUIREMENT
FIXED ASSET CONTINUITY SCHEDULE

FOR PILs CALCULATION

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Smart Meters					
Opening UCC	$ -	$ -	$ 86,942	$ 3,470,109	$ 3,246,586
Capital Additions	$ -	$ 90,565	$ 3,531,377	$ 56,339	$ 35,339
UCC Before Half Year Rule	$ -	$ 90,565	$ 3,618,319	$ 3,526,448	$ 3,281,925
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 45,283	$ 1,765,689	$ 28,170	$ 17,670
Reduced UCC	$ -	$ 45,283	$ 1,852,631	$ 3,498,279	$ 3,264,255
CCA Rate Class	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%
CCA	$ -	$ 3,623	$ 148,210	$ 279,862	$ 261,140
Closing UCC	$ -	$ 86,942	$ 3,470,109	$ 3,246,586	$ 3,020,785
Computer Hardware					
Opening UCC	$ -	$ -	$ -	$ 5,438	$ 2,447
Capital Additions	$ -	$ -	$ 7,500	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ 7,500	$ 5,438	$ 2,447
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ 3,750	$ -	$ -
Reduced UCC	$ -	$ -	$ 3,750	$ 5,438	$ 2,447
CCA Rate Class	45	50	50	50	50
CCA Rate	45%	55%	55%	55%	55%
CCA	$ -	$ -	$ 2,063	$ 2,991	$ 1,346
Closing UCC	$ -	$ -	$ 5,438	$ 2,447	$ 1,101
Computer Software					
Opening UCC	$ -	$ -	$ -	$ 55,528	$ 10,500
Capital Additions	$ -	$ -	$ 111,056	$ 21,000	$ -
UCC Before Half Year Rule	$ -	$ -	$ 111,056	$ 76,528	$ 10,500
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ 55,528	$ 10,500	$ -
Reduced UCC	$ -	$ -	$ 55,528	$ 66,028	$ 10,500
CCA Rate Class	12	12	12	12	12
CCA Rate	100%	100%	100%	100%	100%
CCA	$ -	$ -	$ 55,528	$ 66,028	$ 10,500
Closing UCC	$ -	$ -	$ 55,528	$ 10,500	$ -

Exhibit	Tab	Schedule	Appendix	Contents
10 – LRAM and SSM Amounts				
	1			**Lost Revenue Adjustment Mechanism and Shared Savings Mechanism**
		1		Overview
		2		Summary of LRAM and SSM Amounts
		3		Determination of LRAM Amount
		4		Determination of SSM Amount
		5		Verification and Evaluation of Results
			A	EnerSpectrum Report, Evaluation and Supporting Documents
		6		Proposed Rate Riders and Bill Impacts

LOST REVENUE ADJUSTMENT MECHANISM AND SHARED SAVINGS MECHANISM

Overview

On May 31, 2004, the Minister of Energy granted approval to all electricity distributors in Ontario to apply to the Ontario Energy Board (the "Board") for adjustments to their 2005 electricity distribution rates that would enable them to recover the third tranche of their incremental market adjusted revenue requirement ("third tranche"). The Minister's approval was conditional on a commitment to reinvest an equivalent amount in Conservation and Demand Management ("CDM") initiatives. On February 18, 2005, the Board granted approval to HCHI to proceed with a CDM Plan, as submitted in its application on November 30, 2004, with funding from distribution rates in the amount of $437,478 (Board file no. RP-2004-0203/EB-2004-0523). In addition, HCHI has participated in Ontario Power Authority ("OPA") sponsored CDM programs delivered in 2006 and 2007.

HCHI's CDM efforts have been successful, but as result of decreases in kilowatt-hour ("kWh") consumption and kilowatt ("kW") demand, HCHI has experienced distribution revenue losses in each of the 2006, 2007, 2008 and 2009 years. HCHI has not previously requested approval for the recovery of these foregone revenues on account of these reduced volumes.

The authorization to apply for Lost Revenue Adjustment Mechanism ("LRAM") and Shared Savings Mechanism ("SSM") adjustments is most recently derived from the Board's "*Guidelines for Electricity Distributor Conservation and Demand Management*"– Board file no. EB-2008-0037 – issued March 28, 2008 (the "CDM Guidelines"). These CDM Guidelines provide the Board's policies with respect to applications for LRAM and SSM recovery associated with distribution rate-funded and OPA-funded CDM activities, and replace all policies and guidelines previously issued by the Board in respect of those activities. In conjunction with the CDM Guidelines, the Board's proceeding on

"*Conservation and Demand Management ("CDM") Input Assumptions*" – Board file no. EB-2008-0352 – provides policy on CDM input assumptions. By letter issued January 27, 2009, the Board acknowledged endorsement of the OPA's List of CDM input assumptions. In accordance with the CDM Guidelines including the CDM input assumptions, HCHI is requesting the recovery of historical LRAM and SSM amounts. Prospectively, the impacts of CDM load reductions have been factored into HCHI's 2010 load forecast as part of its 2010 Test year proposed revenue requirement. The details of this are provided in Exhibit 3 – Operating Revenue at Tab 2, Schedule 2, and in particular the adjustment to the 2010 load forecast as a result of incorporating the IESO's 18-Month Outlook which predicts lower demands in part due to conservation.

Haldimand County Hydro Inc. ("HCHI") is requesting recovery of historical LRAM and SSM amounts related to its third tranche/distribution rates funded CDM programs delivered in the years 2005, 2006 and 2007 as well as LRAM amounts related to OPA funded CDM programs delivered in the years 2006 and 2007. HCHI is not currently requesting recovery of LRAM amounts on account of OPA CDM programs delivered in 2008 and 2009. HCHI intends to file for recovery of these amounts at a later date; that is, once the supporting documentation is received from the OPA verifying the energy savings in 2008 and 2009.

Summary of LRAM and SSM Amount

The LRAM amount resulting from third tranche CDM programs is $40,734, and from OPA CDM programs is $316,496, and from combined carrying charges is $26,547 – for a total requested LRAM recovery of $383,777. The total requested SSM recovery amount, in relation only to HCHI's third tranche CDM programs, is $10,027. The total combined LRAM (including carrying charges) and SSM amount requested for recovery is $393,804. HCHI is proposing recovery by way of a single volumetric rate rider effective May 1, 2010, which is concurrent with the distribution rate changes, over a one year recovery period ending April 30, 2011. The LRAM and SSM total requested amounts and corresponding rate riders by rate class are set out in the following Table 1.

Table 1
LRAM and SSM Total Amounts and Rate Riders by Class

	LRAM			SSM	BILLING UNITS (2010)		RATE RIDER (ONE YEAR)		
RATE CLASS	Amounts (2006, 2007, 2008, 2009)	Carrying Charges	LRAM Total	SSM Total			LRAM $ / unit kWh or kw)	SSM $ / unit kWh or kw)	TOTAL $ / unit kWh or kw)
Residential	$ 342,288	$ 25,437	$ 367,724	$ 10,027	169,492,357	kWh	$ 0.0022	$ 0.0001	**$ 0.0022**
G/S < 50 kW	$ 3,518	$ 261	$ 3,779	$ -	60,923,412	kWh	$ 0.0001	$ -	**$ 0.0001**
G/S 50 to 4999 kW (include interval metered)	$ 11,424	$ 849	$ 12,273	$ -	296,554	kW	$ 0.0414	$ -	**$ 0.0414**
Total	**$ 357,230**	**$ 26,547**	**$ 383,777**	**$ 10,027**					

Determination of LRAM Amount

A LRAM accounts for variances between actual CDM results and the corresponding quantities used to set class rates. For 2006 to 2009 rate years, no forecast or other adjustment for the affects of CDM programs were made to the load quantities used to calculate the rates. Therefore, the entire load reduction, net of free ridership, achieved by the eligible CDM programs is subject to LRAM treatment. The calculation of load reduction is based on the energy and demand savings and the lifespan of the technology by rate class. Free ridership is the percentage of participants that would have undertaken a particular measure regardless of a particular CDM program being offered. The LRAM recovery, in the amount of $357,230, has been calculated as the approved savings per measure multiplied by the number of measures implemented for the particular program targeted at each rate class.

A summary of the CDM load impacts by program and customer rate class is set out in the following Table 2.

The foregone revenue is calculated on the load reductions resulting from CDM programs by rate class and the distribution volumetric rate applicable to that class and rate year as set out in the following Table 3.

Table 2
CDM Load Impacts by Program and Rate Class

Class / PROGRAM	Year Implemented	2006		2007		2008		2009		TOTAL	
		kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
THIRD TRANCHE CDM PROGRAMS											
Residential											
Lighten Your Electricity Bill	2005	146,897	22	146,897	22	146,897	22	146,897	22	**587,588**	**88**
Co-Branded Mass Market	2006 & 2007	341,823	9	91,509	0	91,509	0	91,509	0	**616,350**	**9**
Social Housing	2007			27,216	1	54,432	1	54,432	1	**136,080**	**3**
Sub - total Residential		**488,720**	**31**	**265,622**	**23**	**292,838**	**23**	**292,838**	**23**	**1,340,018**	**101**
TOTAL THIRD TRANCHE CDM PROGRAMS		**488,720**	**31**	**265,622**	**23**	**292,838**	**23**	**292,838**	**23**	**1,340,018**	**101**
OPA CDM PROGRAMS											
Residential											
Every Kilowatt Counts (spring)	2006	585,074	4	585,074	4	585,074	4	585,074	4	**2,340,298**	**15**
Secondary Fridge Retirement Pilot	2006	23,952	5	23,952	5	23,952	5	23,952	5	**95,810**	**22**
Every Kilowatt Counts (fall)	2006	949,168	14	949,168	14	949,168	14	949,168	14	**3,796,672**	**57**
The Great Refrigerator Roundup	2007			103,294	13	103,294	13	103,294	13	**309,881**	**39**
Every Kilowatt Counts	2007			558,365	21	551,594	19	551,594	21	**1,661,553**	**62**
Cool Saving Rebate	2006 & 2007	44,594	46	172,261	129	172,261	129	172,261	129	**561,377**	**434**
Peaksaver	2007			0	1	0	1	0	1	**0**	**3**
Summer Savings	2007			698,385	388	698,385	388	0	0	**1,396,770**	**776**
Sub - total Residential		**1,602,789**	**69**	**3,090,500**	**576**	**3,083,729**	**574**	**2,385,344**	**188**	**10,162,361**	**1,408**
General Service < 50 kW											
Social Housing	2007			50,322	6	50,322	6	50,322	6	**150,965**	**18**
Energy Efficiency Assist. - Houses - Pilot	2007			862	1	862	1	862	1	**2,586**	**2**
Sub - total General Service < 50 kW		**0**	**0**	**51,184**	**6**	**51,184**	**6**	**51,184**	**6**	**153,551**	**19**
General Service 50 to 4999 kW											
Demand Response 1	2006 & 2007	0	430	0	706	0	706	0	0	**0**	**1,843**
Other Demand Response	2007			0	59	0	0	0	0	**0**	**59**
Sub - total G/S 50 to 4999 kW		**0**	**430**	**0**	**765**	**0**	**706**	**0**	**0**	**0**	**1,902**
TOTAL OPA CDM PROGRAMS		**1,602,789**	**500**	**3,141,684**	**1,348**	**3,134,912**	**1,287**	**2,436,527**	**195**	**10,315,912**	**3,330**
TOTAL "ALL" PROGRAMS		**2,091,509**	**531**	**3,407,305**	**1,371**	**3,427,750**	**1,310**	**2,729,365**	**218**	**11,655,929**	**3,430**

Table 3
Foregone Revenue by Program and Rate Class

Class / PROGRAM	2006			2007			2008			2009			TOTAL REVENUE
*net of regulatory asset rate rider	Load Unit (kWh or kW)	HCHI Dist'n Volume Rate*	Revenue ($)	Load Unit (kWh or kW)	HCHI Dist'n Volume Rate*	Revenue ($)	Load Unit (kWh or kW)	HCHI Dist'n Volume Rate*	Revenue ($)	Load Unit (kWh or kW)	HCHI Dist'n Volume Rate*	Revenue ($)	
THIRD TRANCHE CDM PROGRAMS													
Residential													
Lighten Your Electricity Bill	146,897	$0.0315	$ 4,165	146,897	$0.0318	$ 4,670	146,897	$0.0313	$ 4,635	146,897	$0.0313	$ 4,611	**$ 18,081**
Co-Branded Mass Market	341,823	$0.0315	$ 9,693	91,509	$0.0318	$ 2,909	91,509	$0.0313	$ 2,888	91,509	$0.0313	$ 2,872	**$ 18,362**
Social Housing				27,216	$0.0318	$ 865	54,432	$0.0313	$ 1,718	54,432	$0.0313	$ 1,709	**$ 4,291**
Sub - Total Residential			**$ 13,858**			**$ 8,444**			**$ 9,241**			**$ 9,192**	**$ 40,734**
TOTAL THIRD TRANCHE CDM PROGRAMS			**$ 13,858**			**$ 8,444**			**$ 9,241**			**$ 9,192**	**$ 40,734**
OPA CDM PROGRAMS													
Residential													
Every Kilowatt Counts (spring)	585,074	$0.0315	$ 16,590	585,074	$0.0318	$ 18,599	585,074	$0.0313	$ 18,462	585,074	$0.0313	$ 18,365	**$ 72,016**
Secondary Fridge Retirement Pilot	23,952	$0.0315	$ 679	23,952	$0.0318	$ 761	23,952	$0.0313	$ 756	23,952	$0.0313	$ 752	**$ 2,948**
Every Kilowatt Counts (fall)	949,168	$0.0315	$ 26,915	949,168	$0.0318	$ 30,173	949,168	$0.0313	$ 29,952	949,168	$0.0313	$ 29,793	**$ 116,832**
The Great Refrigerator Roundup				103,294	$0.0318	$ 2,196	103,294	$0.0313	$ 3,260	103,294	$0.0313	$ 3,242	**$ 8,698**
Every Kilowatt Counts				558,365	$0.0318	$ 11,870	551,594	$0.0313	$ 17,406	551,594	$0.0313	$ 17,314	**$ 46,590**
Cool Saving Rebate	44,594	$0.0315	$ 1,265	172,261	$0.0318	$ 5,476	172,261	$0.0313	$ 5,436	172,261	$0.0313	$ 5,407	**$ 17,583**
Summer Savings				698,385	$0.0318	$ 14,847	698,385	$0.0313	$ 22,038	-	$0.0313	$ -	**$ 36,885**
Sub -Total Residential			**$ 45,449**			**$ 83,923**			**$ 97,309**			**$ 74,872**	**$ 301,553**
General Service < 50 kW													
Social Housing				50,322	$0.0231	$ 1,159	50,322	$0.0228	$ 1,152	50,322	$0.0228	$ 1,147	**$ 3,459**
Energy Efficiency Assist. - Houses - Pilot				862	$0.0231	$ 20	862	$0.0228	$ 20	862	$0.0228	$ 20	**$ 59**
Sub - Total General Service < 50 kW			**$ -**			**$ 1,179**			**$ 1,172**			**$ 1,167**	**$ 3,518**
General Service 50 to 4999 kW													
Demand Response 1	430	$6.0641	$ 2,479	706	$6.1187	$ 4,309	706	$6.0269	$ 4,278	-	$6.0333	$ -	**$ 11,066**
Other Demand Response				59	$6.1187	$ 358	-	$6.0269	$ -	-	$6.0333	$ -	**$ 358**
Sub - Total G/S 50 to 4999 kW			**$ 2,479**			**$ 4,667**			**$ 4,278**			**$ -**	**$ 11,424**
TOTAL OPA CDM PROGRAMS			**$ 47,927**			**$ 89,769**			**$ 102,759**			**$ 76,039**	**$ 316,495**
TOTAL "ALL" PROGRAMS			**$ 61,786**			**$ 98,213**			**$ 112,000**			**$ 85,231**	**$ 357,230**

Foregone revenue amounts corresponding to the reductions in volumes by class were calculated for each rate year using the weighted average for the applicable distribution volumetric rates. HCHI proposes to allocate the foregone distribution revenue from each rate class to the class for recovery through a rate rider to be applied to the distribution volumetric rate component for each class. As noted above, HCHI proposes to implement the rate rider over a one year period from May 1, 2010 to April 30, 2011.

HCHI has included carrying costs in the amount of $26,547 as part of the requested amount for recovery of the LRAM portion of this application. Monthly carrying charges have been applied using the Board's prescribed interest rates as set out in the following Table 4. With respect to opening balances, since the LRAM amounts are annualized, HCHI has calculated the annual average of the Board's prescribed interest rates and applied the average rate to the total annual LRAM amounts.

Table 4
Prescribed Interest Rates for LRAM Carrying Charges

	2006	2007	2008	2009
January	7.25%	4.59%	5.14%	2.45%
February	7.25%	4.59%	5.14%	2.45%
March	7.25%	4.59%	5.14%	2.45%
April	7.25%	4.59%	4.08%	1.00%
May	4.14%	4.59%	4.08%	1.00%
June	4.14%	4.59%	4.08%	1.00%
July	4.59%	4.59%	3.35%	0.55%
August	4.59%	4.59%	3.35%	0.55%
September	4.59%	4.59%	3.35%	0.55%
October	4.59%	5.14%	3.35%	
November	4.59%	5.14%	3.35%	
December	4.59%	5.14%	3.35%	

The calculated LRAM carrying costs are provided in the following Table 5. Carrying costs have been calculated to April 30, 2010 as HCHI is requesting recovery of LRAM effective May 1, 2010.

Table 5
LRAM Carrying Costs Rates and Calculations

	Month	Opening Balance	Deemed Interest Rate	Interest ($)	
	2006	$ 61,786	5.40%	$ 3,337	** Note (1)*
	Jan-07	$ 61,786	0.38%	$ 236	
	Feb-07	$ 61,786	0.38%	$ 236	
	Mar-07	$ 61,786	0.38%	$ 236	
	Apr-07	$ 61,786	0.38%	$ 236	
	May-07	$ 61,786	0.38%	$ 236	
	Jun-07	$ 61,786	0.38%	$ 236	
	Jul-07	$ 61,786	0.38%	$ 236	
	Aug-07	$ 61,786	0.38%	$ 236	
	Sep-07	$ 61,786	0.38%	$ 236	
	Oct-07	$ 61,786	0.43%	$ 265	
	Nov-07	$ 61,786	0.43%	$ 265	
	Dec-07	$ 159,999	0.43%	$ 4,908	** Note (2)*
	Jan-08	$ 159,999	0.43%	$ 685	
	Feb-08	$ 159,999	0.43%	$ 685	
	Mar-08	$ 159,999	0.43%	$ 685	
	Apr-08	$ 159,999	0.34%	$ 544	
	May-08	$ 159,999	0.34%	$ 544	
	Jun-08	$ 159,999	0.34%	$ 544	
	Jul-08	$ 159,999	0.28%	$ 447	
	Aug-08	$ 159,999	0.28%	$ 447	
	Sep-08	$ 159,999	0.28%	$ 447	
	Oct-08	$ 159,999	0.28%	$ 447	
	Nov-08	$ 159,999	0.28%	$ 447	
	Dec-08	$ 271,999	0.28%	$ 4,904	** Note (3)*
	Jan-09	$ 271,999	0.20%	$ 555	
	Feb-09	$ 271,999	0.20%	$ 555	
	Mar-09	$ 271,999	0.20%	$ 555	
	Apr-09	$ 271,999	0.08%	$ 227	
	May-09	$ 271,999	0.08%	$ 227	
	Jun-09	$ 271,999	0.08%	$ 227	
	Jul-09	$ 271,999	0.08%	$ 227	
	Aug-09	$ 271,999	0.05%	$ 125	
	Sep-09	$ 271,999	0.05%	$ 125	
	Oct-09	$ 271,999	0.05%	$ 125	
	Nov-09	$ 271,999	0.05%	$ 125	
	Dec-09	$ 357,230	0.05%	$ 1,094	** Note (4)*
	Jan-10	$ 357,230	0.05%	$ 164	
	Feb-10	$ 357,230	0.05%	$ 164	
	Mar-10	$ 357,230	0.05%	$ 164	
	Apr-10	$ 357,230	0.05%	$ 164	** Note (5)*
				$ 26,547	

Table 5 (continued)
LRAM Carrying Costs Rates and Calculations

Note (1)					
Monthly opening balances are not available for 2006; therefore the carrying charges are calculated on the total 2006 LRAM at the average annual carrying charge rate.					
Note (2)					
Monthly opening balances are not available for 2007; therefore the carrying charges are calculated on the total 2007 LRAM at the average annual carrying charge rate.					
Note (3)					
Monthly opening balances are not available for 2008; therefore the carrying charges are calculated on the total 2008 LRAM at the average annual carrying charge rate.					
Note (4)					
Monthly opening balances are not available for 2009; therefore the carrying charges are calculated on the total 2009 LRAM at the average annual carrying charge rate.					
Note (5)					
Carrying charges are calculated to the end of April 2010 as HCHI is requesting approval for May 1, 2010.					

Determination of SSM Amount

SSM amounts are calculated based on the results of the Total Resource Cost test ("TRC test") – a test that measures the net costs of a CDM program as a resource option based on the total cost of developing and implementing that program.

In measuring the effectiveness of a program, the TRC test examines the benefits of a program, which is typically the avoided resource costs such as electricity, with program costs which include both the local distribution company's ("LDCs") costs and the participant's costs, over the life of the program. The stream of future net benefits is net present valued ("NPV") to a single number and must be greater than zero to be cost effective.

The TRC test also provides for free ridership such that a program with a high degree of free ridership is therefore less cost effective for the LDC to pursue as the program costs will exceed the program benefits.

The amount of the SSM incentive is based on 5% of the NPV of the net benefits of HCHI's CDM programs. Where a CDM program has resulted in net costs as opposed to net benefits, the total SSM claim has been reduced by the NPV of the costs. Only third tranche customer-focused programs that reduce the demand for electricity have been included in the calculation of the SSM amount. The SSM amount requested for recovery is $10,027, calculated on a pre-tax basis, in accordance with the CDM Guidelines and the OPA List of CDM input assumptions. The following Table 6 provides the SSM amounts by program and customer rate class.

As with the LRAM amount, HCHI proposes to allocate the SSM from each rate class to the class for recovery through a rate rider to be applied to the distribution volumetric rate component for each class. Also consistent with the LRAM rate rider, HCHI proposes to implement the rate rider over a one year period from May 1, 2010 to April 30, 2011.

Table 6
SSM Amounts by Program and Rate Class

PROGRAM YEAR / Class / Program	Admin & Qualitative Program Costs	Incremental Costs	Total Benefits	NPV	Benefits/ Cost Ratio	SSM Amount
2005						
Residential						
Lighten Your Electricity Bill						
urban	$ 11,861	$ 6,333	$ 68,797	$ 50,603	$ 3.78	**$ 2,530**
suburban	$ 9,630	$ 5,142	$ 55,858	$ 41,086	$ 3.78	**$ 2,054**
2006						
Residential						
Co-Branded Mass Market						
urban	$ 4,415	$ 4,594	$ 48,441	$ 39,432	$ 5.38	**$ 1,972**
suburban	$ 3,569	$ 3,713	$ 39,156	$ 31,874	$ 5.38	**$ 1,594**
2007						
Residential						
Co-Branded Mass Market						
urban	$ 11,882	$ 1,054	$ 19,276	$ 6,340	$ 1.49	**$ 317**
suburban	$ 9,535	$ 846	$ 15,468	$ 5,088	$ 1.49	**$ 254**
Social Housing						
urban		$ 1,398	$ 15,893	$ 14,495	$ 11.37	**$ 725**
suburban		$ 1,122	$ 12,753	$ 11,631	$ 11.37	**$ 582**
TOTALS	$ 50,891	$ 21,683	$ 246,997	$ 174,422	$ 21.30	**$ 10,027**

Verification and Evaluation of Results

The OEB's concluding policy letter of January 27, 2009 (EB-2008-0352) states that "…*The Board has determined that it will endorse the OPA List for use by distributors for the purposes of applications for new distribution rate-funded CDM programs, Lost Revenue Adjustment Mechanism ("LRAM ")and Shared Savings Mechanism (" SSM") at this time*", and further that "…*At this time, the Board would like to clarify that the estimates for savings and adjustment factors used for the calculation of LRAM should be the best available at the time of the third party assessment referred to in Section 7.5 of Guidelines for the Electricity Distributor Conservation and Demand Management ("Guidelines")*". Section 7.5 of The CDM Guidelines includes the same requirements and elaborates to include "…*Where a distributor is making a claim for LRAM and/or SSM in relation to programs funded through distribution rates, distributors should engage an independent third party…in relation to programs funded in 2007 and beyond…*" and for programs funded by the OPA "*…The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient*". HCHI's LRAM and SSM amounts relate to third tranche CDM programs and the OPA provincial CDM programs delivered in 2006 and 2007. HCHI did not engage in CDM activities funded through distribution rates in 2007 and beyond.

The SSM and LRAM claim was prepared by EnerSpectrum Group, an independent third party, who observe that "…*Haldimand County Hydro's approach was found to be consistent with the Board's CDM Guidelines…*" as noted in their report "Haldimand County Hydro Inc. LRAM and SSM Support", dated August 18, 2009. The EnerSpectrum Group's report, including their full evaluation and supporting documents is provided in **Appendix A**.

Proposed Rate Riders and Bill Impacts

HCHI considers its LRAM and SSM in the total amount of $393,804 to be material to its operations, and requests recovery by customer class through the distribution volumetric rate rider. HCHI proposes that the LRAM and SSM rate riders be combined into, and recovered through, a single distribution volumetric rate rider, as provided above in Table 1, to be implemented effective May 1, 2010 over a one year recovery period. The proposed single rate riders that result from the combined LRAM and SSM amounts as requested and the corresponding bill impacts are provided in the following Table 7. HCHI submits that the total bill impacts over the 12 month period as proposed are minimal and do not warrant mitigation by way of an extended recovery period.

Table 7
Proposed Combined LRAM and SSM Rate Riders and Bill Impacts

RATE CLASS	PROPOSED RATE RIDER		MONTHLY BILL IMPACT		
	$	Metric	Volume	Monthly Charge ($)	Total Bill Impact (%)
Residential	$ 0.0022	kWh	800 kWh	$ 1.76	1.46%
General Service < 50 kW	$ 0.0001	kWh	2000 kWh	$ 0.20	0.08%
General Service 50 to 4999 kW	$ 0.0414	kW	100 kW	$ 4.14	0.06%
General Service 50 to 4999 kW (Interval Metered)	$ 0.0414	kW	500 kW	$ 20.70	0.08%

EnerSpectrum Group

The preferred source for utility management expertise.

Haldimand County Hydro Inc.

LRAM and SSM Support

August 18, 2009

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., Managing Partner

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1. Introduction

Haldimand County Hydro Inc. maintains a long-term commitment to Conservation and Demand Management (CDM) for the benefit of its customers and community. This commitment commenced with public conservation and safety awareness campaigns in previous decades, and expanded to targeted CDM programming, funded by the Third Tranche rate increase and implemented locally and regionally with Haldimand County Hydro's partners in the Niagara Erie Power Alliance (NEPA). This commitment continues to grow through the implementation of CDM programs from the Ontario Power Authority (OPA).

As this report sets out, programs were implemented between January, 2005 and 2008, and the resulting energy savings recorded for the period from January 1, 2006 to December 31, 2009, are outlined in Attachment A. Haldimand County Hydro's CDM programming has resulted in energy savings of 11.66 million kWh for customers, reduced the load on the distribution system by 3,430 kW, ultimately helping reduce the need for electricity generation. This includes programming implemented under Third Tranche funding from 2005 to September 2007, and under OPA-sponsored programs from 2006 and 2007. No reporting or claim for OPA programs delivered in 2008 and 2009 is being undertaken as part of this evaluation because no data is available at this time. These impacts will be included in a future rate application.

With the Green Energy Act now part of Ontario legislation, the opportunities and obligations of LDCs to expand their CDM activities have increased to include renewable generation, and even greater conservation targets in the years ahead. This makes it important to begin the process of claiming compensation for revenues lost to successful CDM activities, and for the shared societal savings in future from successful CDM programs today. It provides Haldimand County Hydro with a baseline for its LRAM and SSM claims and embeds a process for these claims so that future CDM investment is sustainable for the LDC in the long term.

The Ontario Energy Board (OEB) introduced a process outlined in the March 28, 2008 Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037[1]) ("CDM Guidelines") for rate-based applications to recover revenues lost to customer energy conservation, and to share in gains from effective CDM programs prior to the completion of Third Tranche CDM programs. The mechanisms developed by the OEB to calculate lost revenue or savings are the Lost Revenue Adjustment Mechanism (LRAM) and the Shared Savings Mechanism (SSM).

SSM is calculated as 5% of the net present value of the future net benefits from CDM investments. LRAM calculations are made from the energy savings data from measured CDM program results, or other documented results as applied to the affected rate class. OPA sponsored programs, such as Every Kilowatt Counts, are not eligible for SSM because the OPA compensates LDCs through a contractual arrangement rather than the LDC recovering SSM amounts through rate riders. However OPA programs do represent the potential for lost revenue to the LDC, and may be claimed under LRAM.

[1] See Appendix E

The application for LRAM and SSM compensation that Haldimand County Hydro is considering as part of its 2010 rates filing is based on its 2006 to 2009 inclusive CDM results, and represents a significant milestone in the LDC's CDM record. Equally important, the application represents a process that should become a standard element in future rate filings, again to help ensure the sustainability of CDM programming that benefits all in the future.

2. Required

Haldimand County Hydro Inc. has asked EnerSpectrum Group to assist with LRAM and SSM assessment. The firm previously assisted the LDC in preparing its CDM TRC results in 2006 as part of the annual CDM reporting to the OEB. In completing the scope of work related to LRAM and SSM, EnerSpectrum Group will:

1. Review Third Tranche Total Resource Cost (TRC) calculations and underlying data prepared by HCH for annual year end CDM reports, and assess compliance with the Guidelines and make recommendations for SSM claims as appropriate
2. Assess energy savings to calculate lost revenue consistent with Haldimand County Hydro Inc.'s CDM results (Third Tranche and OPA programs); prepare LRAM calculations suitable for submission
3. Summarize SSM and LRAM calculations and assumptions suitable for inclusion in Haldimand County Hydro Inc.'s rates application, with supporting details.
4. In performing the above tasks, EnerSpectrum Group's involvement is intended to constitute 3rd party review as specified in OEB Guidelines.

3. About SSM/LRAM

LRAM/SSM application is governed by the OEB issued GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT, EB-2008-0037.

For SSM, a distributor may recover 5% of the net benefits (TRC) created by CDM portfolio investments. An SSM claim applies only to customer focused initiatives that reduce the demand for electricity and/or the amount of energy used. Programs designed to improve Distribution System efficiency (eg. loss reduction) and OPA sponsored programs (eg., Every Kilowatt Counts) are excluded from SSM considerations.

LRAM is calculated as the product of the demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to the class (net of Regulatory Asset Recovery rate riders). OPA sponsored program kW/kWh s are eligible for LRAM.

4. Methodology

To optimize the calculation of LRAM and SSM amounts, EnerSpectrum Group:

1. Reviewed existing LRAM and SSM CDM Guidelines and precedents set through LDC submissions to the OEB, to identify the most prudent course for Haldimand County Hydro Inc. to complete its LRAM and SSM applications.
2. Sought counsel within OEB staff to validate assumptions and processes to complete LRAM and SSM submissions consistent with other LDC submissions. Validation by each specific technology employed is included in the accompanying documentation.
3. Reviewed Haldimand County Hydro CDM program results and TRC calculations, verified assumptions and calculations, identified variances with reported values, and recommended adjustments as appropriate appear in the accompanying documentation. Actual program results were provided by Haldimand County Hydro, including CDM Annual Reports, OPA program results reports, and supplemental information relevant to LRAM and SSM calculations. Haldimand County Hydro's approach was found to be consistent with the Board's CDM Guidelines Prepared report and recommendations related to LRAM and SSM calculations consistent with OEB CDM Guidelines which are in the accompanying documentation.

5. Results

In assessing and applying results from CDM programming to TRC, LRAM or SSM calculations, program results are assumed to begin after the program implementation has been completed. For this reason, the results of specific programs have been staggered into subsequent months or years to more accurately reflect the timing of the impacts from CDM programs. Where the results from a CDM program are reasonably expected to begin flowing in the same year, LRAM calculations will be prorated to the end of that year. It should also be noted that TRC amounts used in the calculation of SSM for eligible CDM programs were based on the CDM Guidelines.

The timing of results used in LRAM calculations for OPA sponsored programs are contained in the accompanying documentation under OPA Conservation Results, issued July 14, 2009.

The accompanying table below sets out the assessed amounts for LRAM and SSM for Haldimand County Hydro's Third Tranche CDM programming and 2006 and 2007. The calculation of the results, by program and customer class as applicable, are explained in the text below, and detailed in the appended attachments.

LRAM and SSM Totals by Class

Rate Class

	LRAM	SSM
Residential		
Third Tranche		
urban	$22,533.17	$5,543.51
suburban	$18,201.32	$4,483.93
Residential		
OPA Conservation Programs		
urban	$166,940.50	
suburban	$134,613.09	
General Service<50kW		
OPA Conservation Programs	$3,518.02	
General Service>50kW to 4,999kW		
OPA Conservation Programs	$11,424.04	
Unmetered Scattered Load		
OPA Conservation Programs	$0.00	
TOTALS	$357,230.14	$10,027.43

6. Determination of SSM Amount

For SSM, a distributor may recover 5% of the net benefits (TRC) created by CDM portfolio investments. As set out in the Guidelines, program net benefits are determined by the present value of the avoided electricity costs over the technology's/program's life minus the present value of program costs. All results are net of free ridership. Incentive payments identified by HCH are excluded from these calculations. For all programs/projects, the most recently published OPA assumptions and measures list were used in TRC calculations in accordance with OEB's direction letter, Conservation and Demand Management ("CDM") Input Assumptions Board File No.: EB-2008-0352, January 27, 2009.

EnerSpectrum Group has validated applied TRC methodology against the CDM Guidelines (included in documentation) and calculated net TRC benefits for each CDM program. CDM incremental general administrative costs were included as part of overall portfolio TRC costs.

EnerSpectrum Group's TRC Calculator © was used to ensure appropriate application of avoided costs, free ridership, discounted future benefits, energy efficiency technology life.

Utility-side programs, such as loss reduction initiatives, are not eligible for SSM treatment and as such, HCH's Hagersville 4 kV to 27.6kV conversion (system loss reduction) program was excluded from these calculations. Also excluded were results from OPA sponsored programs (e.g., Every Kilowatt Counts).

Programs considered for this application are described in annually submitted year end CDM reports for 2005, 2006, 2007 and 2008. For each eligible program, net load reductions were calculated (net of free ridership) for both SSM and LRAM calculations. Attachment A summarizes these load reductions.

The applied discount rates for Haldimand County Hydro Inc.(approved Weighted Average Cost of Capital) were 8.56%, 7.52%, and 7.73% for the years 2005, 2006 and 2007 respectively.

The sum of all program NPVs, is $200,548.66, resulting in the SSM claim of $10,027.43.

Attachment C summarizes the calculation of the SSM amounts by program and in total. Attachment E summarizes individual technology TRC (NPV) values by program. The supporting source data and TRC calculations are set out in detail in the documentation accompanying this report.

7. Determination of LRAM Amount

LRAM amounts were identified by rate class consistent with the CDM Guidelines for programs that impacted revenues from 2006 to 2009. No forecast or other adjustment for the effects of CDM programs was made to the load quantities used in the preparation of HCH's rate cases in prior years. The entire actual load reduction achieved by the eligible CDM programs is subject to LRAM treatment. In addition, OPA sponsored programs, although ineligible for additional SSM incentives, represent lost revenue through their successful implementation and are included in LRAM calculations.

For Haldimand County Hydro programs, load impacts were assessed based on the same per unit energy savings (OPA approved Assumptions and Measures) as used in SSM calculations, augmented by OPA results (Attachment A). These OPA-approved Assumptions and Measures are embedded in the TRC Calculator used to compute LRAM and SSM amounts.

The sum of all program LRAM calculations, including OPA sponsored programs is $357,230.14

Attachment B summarizes the CDM load impacts by program and rate class and the resultant revenue impacts.

8. Allocation and Manner of Recovery for SSM/LRAM Amounts

Consistent with the proposed approach for the LRAM amounts, the SSM/LRAM amounts arising from CDM programs in each rate class are allocated to that class for recovery. In cases where programs span more than one density rate class (eg., residential urban and suburban), the SSM/LRAM amounts per class are proportional to the total energy delivered for each class.

LRAM and SSM rate riders be combined and expressed as a single rate rider for each class, based on approaches taken by other LDCs.

9. Rate Implementation

HCH will determine the appropriate rate riders for recovery of the following revenue adjustments based upon its load forecast for each rate class.:

LRAM and SSM Totals by Class

Rate Class	LRAM	SSM
Residential		
Third Tranche		
urban	$22,533.17	$5,543.51
suburban	$18,201.32	$4,483.93
Residential		
OPA Conservation Programs		
urban	$166,940.50	
suburban	$134,613.09	
General Service<50kW		
OPA Conservation Programs	$3,518.02	
General Service>50kW to 4,999kW		
OPA Conservation Programs	$11,424.04	
Unmetered Scattered Load		
OPA Conservation Programs	$0.00	
TOTALS	$357,230.14	$10,027.43

10. Recommendations

EnerSpectrum Group recommends the following:

1. SSM/LRAM amounts arising from CDM programs in each rate class be allocated to that class for recovery. In cases where programs span more than one density rate class (eg., residential urban and suburban), the SSM/LRAM amounts per class are proportional to the total energy delivered for each class.
2. In cases where SSM and LRAM amounts span more than one rate class, calculate SSM and LRAM as separate rate riders but combine them into one rate rider for application to rates, as has been done by other LDCs.
3. Incorporate future impacts of CDM programming which occurred during the period 2005 to 2008 inclusive into the Cost of Service application for rates to be effective May 1, 2010. This recognizes CDM as an established customer service element in the years ahead, with identifiable costs and benefits, and better serves Haldimand County Hydro with regard to the Green Energy Act requirements
4. Use SSM calculation as one of the methods to assess the potential of CDM programs considered for implementation.
5. Monitor OPA information and reports pursuant to its email of July 14, 2009 to all LDC conservation officers and program managers. The OPA stated that "2008 results are still preliminary and are subject to change" As a result, this evaluation did not consider any CDM programs operated during 2008 and 2009. Haldimand County Hydro LRAM claims will be reviewed and calculated once final results are provided by the OPA.

Attachment A

CDM Load Impacts by Class and Program

Class / Program	Year Implemented	2005 kWh	2005 kW	2006 kWh	2006 kW	2007 kWh	2007 kW	2008 kWh	2008 kW	2009 kWh	2009 kW	**Total kWh**	**Total kW**
Residential													
Third Tranche													
Lighten Your Electricity Bill	2005			146,896.91	22.07	146,896.91	22.07	146,896.91	22.07	146,896.91	22.07	**587,588**	**88.26**
Co-Branded Mass Market	2006 & 2007			341,823.21	9.38	91,508.94	0.00	91,508.94	0.00	91,508.94	0.00	**616,350**	**9.38**
Social Housing	2007					27,216.00	0.63	54,432.00	1.26	54,432.00	1.26	**136,080**	**3.15**
Residential													
OPA Conservation Programs													
Every Kilowatt Counts (spring)	2006			585,074.41	3.81	585,074.41	3.81	585,074.41	3.81	585,074.41	3.81	**2,340,298**	**15.25**
Secondary Fridge Retirement Pilot	2006			23,952.40	5.43	23,952.40	5.43	23,952.40	5.43	23,952.40	5.43	**95,810**	**21.72**
Every Kilowatt Counts (fall)	2006			949,167.94	14.28	949,167.94	14.28	949,167.94	14.28	949,167.94	14.28	**3,796,672**	**57.13**
The Great Refrigerator Roundup	2007					103,294	12.85	103,293.72	12.85	103,294	12.85	**309,881**	**38.55**
Every Kilowatt Counts	2007					558,365	21.44	551,593.88	19.43	551,594	21.44	**1,661,553**	**62.31**
Cool Saving Rebate	2006 & 2007			44,593.88	45.68	172,261	129.49	172,261	129.49	172,261	129.49	**561,377**	**434.15**
Peaksaver	2007					0	1.13	0	1.13	0	1.13	**0**	**3.40**
Summer Savings	2007					698,385	387.99	698,385	387.99	0	0	**1,396,770**	**775.98**
General Service<50kW													
OPA Conservation Programs													
Affordable Housing	2007					0	0	0	0	0	0	**0**	**0**
Social Housing	2007					50,322	5.92	50,322	5.92	50,322	5.92	**150,965**	**17.76**
Energy Efficiency Assistance for Houses - Pilot	2007					862	0.54	862	0.54	862	0.54	**2,586**	**1.63**
Toronto Comprehensive	2007					0	0	0	0	0	0	**0**	**0**
Electricity Retrofit Incentive Program (ERIP)	2007					0	0	0	0.00	0	0.00	**0**	**0.00**
General Service>50kW to 4,999kW													
OPA Conservation Programs													
Demand Response 1	2006 & 2007			0.00	430.36	0	706.28	0	706.28	0	0	**0**	**1,842.93**
Other Demand Response	2007					0	58.75	0	0.00	0	0	**0**	**58.75**
Unmetered Scattered Load													
OPA Conservation Programs													
Renewable Energy Standard Offer Program (RESOP)	2007					0	0	0	0.00	0	0.00	**0**	**0.00**
TOTALS		0	0	2,091,508.75	531.01	3,407,305.47	1,370.61	3,427,750.11	1,310.49	2,729,364.91	218.23	**11,655,929.25**	**3,430.34**

Attachment B

Foregone Revenue by Class and Program

Class / Program		2006			2007			2008			2009			Total Revenue	Total Revenue By Class
		Load Unit (kWh or kW)	HCH Distribution Volumetric Rate*	Revenue	Load Unit (kWh or kW)	HCH Distribution Volumetric Rate*	Revenue	Load Unit (kWh or kW)	HCH Distribution Volumetric Rate*	Revenue	Load Unit (kWh or kW)	Rate per Unit	Revenue		
Residential															
Third Tranche															
Lighten Your Electricity Bill	urban	81,233.99	0.0315	2,296.21	81,498.41	0.0318	2,583.50	81,483.72	0.0313	2,564.02	81,909.72	0.0313	2,563.77	**10,007.51**	
	suburban	65,662.92	0.0317	1,869.20	65,398.51	0.0320	2,086.21	65,413.20	0.0315	2,071.42	64,987.19	0.0315	2,047.10	**8,073.93**	**18,081.44**
Co-Branded Mass Market	urban	189,028.24	0.0315	5,343.20	50,769.16	0.0318	1,609.38	50,760.01	0.0313	1,597.25	51,025.38	0.0313	1,597.09	**10,146.92**	
	suburban	152,794.97	0.0317	4,349.56	40,739.78	0.0320	1,299.60	40,748.93	0.0315	1,290.38	40,483.56	0.0315	1,275.23	**8,214.78**	**18,361.70**
Social Housing	urban				15,099.44	0.0318	478.65	30,193.43	0.0313	950.09	30,351.28	0.0313	950.00	**2,378.73**	
	suburban				12,116.56	0.0320	386.52	24,238.57	0.0315	767.55	24,080.72	0.0315	758.54	**1,912.62**	**4,291.35**
Total Third Tranche Residential															**40,734.49**
Residential															
OPA Conservation Programs															
Every Kilowatt Counts (spring)	urban	323,546.15	0.0315	9,145.57	324,599.28	0.0318	10,289.80	324,540.78	0.0313	10,212.22	326,237.49	0.0313	10,211.23	**39,858.82**	
	suburban	261,528.26	0.0317	7,444.84	260,475.13	0.0320	8,309.16	260,533.63	0.0315	8,250.23	258,836.92	0.0315	8,153.36	**32,157.59**	**72,016.41**
Secondary Fridge Retirement Pilot	urban	13,245.68	0.0315	374.41	13,288.79	0.0318	421.25	13,286.40	0.0313	418.08	13,355.86	0.0313	418.04	**1,631.78**	
	suburban	10,706.72	0.0317	304.78	10,663.61	0.0320	340.17	10,666.00	0.0315	337.76	10,596.54	0.0315	333.79	**1,316.50**	**2,948.28**
Every Kilowatt Counts (fall)	urban	524,889.87	0.0315	14,836.89	526,598.37	0.0318	16,693.17	526,503.45	0.0313	16,567.31	529,256.04	0.0313	16,565.71	**64,663.08**	
	suburban	424,278.07	0.0317	12,077.78	422,569.57	0.0320	13,479.97	422,664.48	0.0315	13,384.38	419,911.90	0.0315	13,227.22	**52,169.35**	**116,832.43**
The Great Refrigerator Roundup	urban				57,307.36	0.0318	1,214.92	57,297.03	0.0313	1,802.95	57,596.58	0.0313	1,802.77	**4,820.64**	
	suburban				45,986.36	0.0320	981.04	45,996.69	0.0315	1,456.56	45,697.14	0.0315	1,439.46	**3,877.06**	**8,697.70**
Every Kilowatt Counts	urban				309,781.03	0.0318	6,567.36	305,969.12	0.0313	9,627.83	307,568.75	0.0313	9,626.90	**25,822.09**	
	suburban				248,584.20	0.0320	5,303.13	245,624.75	0.0315	7,778.12	244,025.13	0.0315	7,686.79	**20,768.04**	**46,590.13**
Cool Saving Rebate	urban	24,660.42	0.0315	697.07	95,570.50	0.0318	3,029.58	95,553.28	0.0313	3,006.74	96,052.83	0.0313	3,006.45	**9,739.85**	
	suburban	19,933.47	0.0317	567.44	76,690.68	0.0320	2,446.43	76,707.90	0.0315	2,429.08	76,208.35	0.0315	2,400.56	**7,843.52**	**17,583.37**
Peaksaver	urban				0	0.0318	0	0	0.0313	0	0	0.0313	0	**0**	
	suburban				0	0.0320	0	0	0.0315	0	0	0.0315	0	**0**	**0**
Summer Savings	urban				387,464.11	0.0318	8,214.24	387,394.27	0.0313	12,190.01	0	0.0313	0	**20,404.25**	
	suburban				310,921.09	0.0320	6,632.98	310,990.93	0.0315	9,848.05	0	0.0315	0	**16,481.03**	**36,885.27**
Total OPA Conservation Programs Residential															**301,553.59**
General Service<50kW															
OPA Conservation Programs															
Affordable Housing					0	0.0231	0	0	0.0228	0	0	0.0228	0	**0**	
Social Housing					50,321.70	0.0231	1,159.08	50,321.70	0.0228	1,152.37	50,321.70	0.0228	1,147.33	**3,458.78**	
Energy Efficiency Assistance for Houses - Pilot					861.83	0.0231	19.85	861.83	0.0228	19.74	861.83	0.0228	19.65	**59.24**	
Toronto Comprehensive					0	0.0231	0	0	0.0228	0	0	0.0228	0	**0**	
Electricity Retrofit Incentive Program (ERIP)					0	0.0231	0	0.00	0.0228	0.00	0.00	0.0228	0.00	**0.00**	**3,518.02**
General Service>50kW to 4,999kW															
OPA Conservation Programs															
Demand Response 1		430.36	6.0641	2,478.70	706.28	6.1187	4,308.67	706.28	6.0269	4,278.30	0	6.0333	0	**11,065.66**	
Other Demand Response					58.75	6.1187	358.38	0.00	6.0269	0.00	0	6.0333	0	**358.38**	**11,424.04**
Unmetered Scattered Load															
OPA Conservation Programs															
Renewable Energy Standard Offer Program (RESOP)					0	0.0239	0	0.00	0.0235	0.00	0.00	0.0235	0.00	**0.00**	**0.00**
TOTALS															**357,230.14**

*net of regulatory asset rate rider

Attachment C

SSM Amounts by Class and Program

Class Program	Admin & Qualitative Program Costs	Incremental Costs	Total Benefits	NPV	Benefits/ Cost Ratio	SSM Amount
2005						
Residential						
Lighten Your Electricity Bill						
urban	$11,860.73	$6,333.47	$68,797.16	$50,602.96	$3.78	$2,530.15
suburban	$9,630.00	$5,142.29	$55,857.96	$41,085.68	$3.78	$2,054.28
2006						
Residential						
Co-Branded Mass Market						
urban	$4,415.12	$4,594.05	$48,441.35	$39,432.18	$5.38	$1,971.61
suburban	$3,568.82	$3,713.45	$39,156.03	$31,873.76	$5.38	$1,593.69
2007						
Residential						
Co-Branded Mass Market						
urban	$11,881.96	$1,054.12	$19,276.17	$6,340.09	$1.49	$317.00
suburban	$9,534.70	$845.88	$15,468.19	$5,087.61	$1.49	$254.38
Social Housing						
urban		$1,398.10	$15,893.01	$14,494.92	$11.37	$724.75
suburban		$1,121.90	$12,753.37	$11,631.46	$11.37	$581.57
TOTALS	$50,891.33	$21,683.26	$246,996.87	$200,548.66	$21.30	$10,027.43

Attachment D

LRAM and SSM Totals by Class

Rate Class

	LRAM	SSM
Residential		
Third Tranche		
urban	$22,533.17	$5,543.51
suburban	$18,201.32	$4,483.93
Residential		
OPA Conservation Programs		
urban	$166,940.50	
suburban	$134,613.09	
General Service<50kW		
OPA Conservation Programs	$3,518.02	
General Service>50kW to 4,999kW		
OPA Conservation Programs	$11,424.04	
Unmetered Scattered Load		
OPA Conservation Programs	$0.00	
TOTALS	$357,230.14	$10,027.43

Attachment E

Programs	OPA Table Applied	Element No.	EE Technology Life	Start Year	Incremental Costs	Discount Factor	TRC NPV
2005							
Lighten Your Electricity Bill - CFL 11W	Residential	23	8	2005	-$1,863.00	8.56%	$12,257.17
Lighten Your Electricity Bill - CFL 15W	Residential	24	8	2005	-$900.00	8.56%	$8,661.44
Lighten Your Electricity Bill - LED Lights - 5 Watt	Residential	35	30	2005	$2,423.45	8.56%	$67,723.19
Lighten Your Electricity Bill - LED Lights - Incandescent Mini Lights	Residential	36	30	2005	$2,423.45	8.56%	$6,319.81
Lighten Your Electricity Bill - Outdoor and Indoor Timers	Residential	40	10	2005	$1,777.86	8.56%	$32.79
Lighten Your Electricity Bill - Programmable Thermostat	Residential	88	18	2005	$7,614.00	8.56%	$18,184.97
2006							
Co-Branded Mass Market - Cold Water Washing	Residential	20	1	2006	$4,507.50	7.52%	$13,220.37
Co-Branded Mass Market - LED christmas lights 5 Watt	Residential	35	30	2006	$1,900.00	7.52%	$60,222.21
Co-Branded Mass Market - LED christmas lights Mini Watt	Residential	36	30	2006	$1,900.00	7.52%	$5,847.31
2007							
Co-Branded Mass Market (low income) - CFL 15W	Residential	24	8	2007	-$2,520.00	7.73%	$26,126.38
Co-Branded Mass Market - LED christmas lights 5 Watt	Residential	35	30	2007	$950.00	7.73%	$29,940.31
Co-Branded Mass Market - LED christmas lights Mini Watt	Residential	36	30	2007	$950.00	7.73%	$2,904.05

SubTotal **$251,439.99**

Admin & Qualitative Program Costs **$50,891.33**

Total **$200,548.66**

APPENDIX A

LRAM and SSM Supporting Material 2005 Lighten Your Electricity Bill LRAM, SSM, Assumptions

98 Archibald Road, RR2, Kettleby, Ontario, L0G 1J0
Phone: 905.939.8239 Fax: 905.939.4606
Web: www.enerspectrum.com

Assumptions:	2005	
Programs:	Lighten Your Electricity Bill - CFL 11W	Lighten Your Electricity Bill - CFL 15W
OPA Table Applied:	Residential	Residential
Element No.:	23	24
Number of Units:	1035	500
EE Technology Life:	8	8
Start Year:	2005	2005
Incremental Costs:	1863	900
Discount Factor:	8.56%	8.56%
LDC Costs:	summarized at portfolio level	summarized at portfolio level
Free Ridership Rate:	10%	10%
TRC NPV:	$12,257.17	$8,661.44
Y/E CDM Reported TRC:	$81,367.17	
Difference:	-$60,448.57	
Reason for Difference:	Performed separate TRC calculations for each technology	
	Free ridership per (updated) OPA tables applied	
	Study period adjusted to 8 years from 20 years	
	Calculations were based on new (updated) OPA tables	

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
CFL Screw-in 11W	-1,863	10,394	12,257	5.58	613	25,803	28,670	1	1	10%	1,035	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 11W	Urban	14,240	15,823	1	1	10%	0.03150		403	0	571	8
	Suburban	11,562	12,847	0	0	10%	0.03170		329	0	464	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 11W	Urban	14,240	15,823	1	1	10%	0.03180		451	0	571	8
	Suburban	11,562	12,847	0	0	10%	0.03200		369	0	464	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 11W	Urban	14,240	15,823	1	1	10%	0.03130		448	0	571	8
	Suburban	11,562	12,847	0	0	10%	0.03150		366	0	464	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 11W	Urban	14,240	15,823	1	1	10%	0.03130		446	0	571	8
	Suburban	11,562	12,847	0	0	10%	0.03150		364	0	464	8
Commercial												
Industrial												

Assumptions:	2005	
Programs:	Lighten Your Electricity Bill - CFL 11W	Lighten Your Electricity Bill - CFL 15W
OPA Table Applied:	Residential	Residential
Element No.:	23	24
Number of Units:	1035	500
EE Technology Life:	8	8
Start Year:	2005	2005
Incremental Costs:	1863	900
Discount Factor:	8.56%	8.56%
LDC Costs:	summarized at portfolio level	summarized at portfolio level
Free Ridership Rate:	10%	10%
TRC NPV:	$12,257.17	$8,661.44
Y/E CDM Reported TRC:	$81,367.17	
Difference:	-$60,448.57	
Reason for Difference:	Performed separate TRC calculations for each technology	
	Free ridership per (updated) OPA tables applied	
	Study period adjusted to 8 years from 20 years	
	Calculations were based on new (updated) OPA tables	

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
CFL Screw-in 15W	-900	7,761	8,661	8.62	433	19,440	21,600	0	1	10%	500	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 15W	Urban	10,729	11,921	0	0	10%	0.03150		303	0	276	8
	Suburban	8,711	9,679	0	0	10%	0.03170		248	0	224	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 15W	Urban	10,729	11,921	0	0	10%	0.03180		340	0	276	8
	Suburban	8,711	9,679	0	0	10%	0.03200		278	0	224	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 15W	Urban	10,729	11,921	0	0	10%	0.31300		338	0	276	8
	Suburban	8,711	9,679	0	0	10%	0.03150		276	0	224	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 15W	Urban	10,729	11,921	0	0	10%	0.03130		336	0	276	8
	Suburban	8,711	9,679	0	0	10%	0.03150		274	0	224	8
Commercial												
Industrial												

Assumptions:	2005	
Programs:	Lighten Your Electricity Bill - LED Lights - 5 Watt	Lighten Your Electricity Bill - LED Lights - Incandescent Mini Lights
OPA Table Applied:	Residential	Residential
Element No.:	35	36
Number of Units:	1275.5	1275.5
EE Technology Life:	30	30
Start Year:	2005	2005
Incremental Costs:	-2423.45	-2423.45
Discount Factor:	8.56%	8.56%
LDC Costs:	summarized at portfolio level	summarized at portfolio level
Free Ridership Rate:	5%	5%
TRC NPV:	$67,723.19	$6,319.81
Y/E CDM Reported TRC:	$23,161.11	
Difference:	$50,881.90	
Reason for Difference:	Performed separate TRC calculations for each technology	
	Free ridership per OPA tables applied	
	Calculations based on new OPA tables (kWh saved/unit)	

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
LED Christmas Lights (indoor or outdoor)	2,423	70,147	67,723	28.94	3,386	69,068	72,704	0	0	5%	1,276	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	38,119	40,125	0	0	5%	0.03150		1,077	0	704	30
	Suburban	30,950	32,578	0	0	5%	0.03170		881	0	572	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	38,119	40,125	0	0	5%	0.03180		1,208	0	704	30
	Suburban	30,950	32,578	0	0	5%	0.03200		987	0	572	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	38,119	40,125	0	0	5%	0.03130		1,199	0	704	30
	Suburban	30,950	32,578	0	0	5%	0.03150		980	0	572	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	38,119	40,125	0	0	5%	0.03130		1,193	0	704	30
	Suburban	30,950	32,578	0	0	5%	0.03150		975	0	572	30
Commercial												
Industrial												

Assumptions:	2005	
Programs:	Lighten Your Electricity Bill - LED Lights - 5 Watt	Lighten Your Electricity Bill - LED Lights - Incandescent Mini Lights
OPA Table Applied:	Residential	Residential
Element No.:	35	36
Number of Units:	1275.5	1275.5
EE Technology Life:	30	30
Start Year:	2005	2005
Incremental Costs:	-2423.45	-2423.45
Discount Factor:	8.56%	8.56%
LDC Costs:	summarized at portfolio level	summarized at portfolio level
Free Ridership Rate:	5%	5%
TRC NPV:	$67,723.19	$6,319.81
Y/E CDM Reported TRC:	$23,161.11	
Difference:	$50,881.90	
Reason for Difference:	Performed separate TRC calculations for each technology	
	Free ridership per OPA tables applied	
	Calculations based on new OPA tables (kWh saved/unit)	

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
LED Christmas Lights (indoor or outdoor)	2,423	8,743	6,320	3.61	316	8,745	9,205	0	0	5%	1,276	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	4,826	5,080	0	0	5%	0.03150		136	0	704	30
	Suburban	3,919	4,125	0	0	5%	0.03170		112	0	572	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	4,826	5,080	0	0	5%	0.03180		153	0	704	30
	Suburban	3,919	4,125	0	0	5%	0.03200		125	0	572	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	4,826	5,080	0	0	5%	0.03130		152	0	704	30
	Suburban	3,919	4,125	0	0	5%	0.03150		124	0	572	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	4,826	5,080	0	0	5%	0.03130		151	0	704	30
	Suburban	3,919	4,125	0	0	5%	0.03150		123	0	572	30
Commercial												
Industrial												

Assumptions:	2005
Programs:	Lighten Your Electricity Bill - Outdoor and Indoor Timers
OPA Table Applied:	Residential
Element No.:	40
Number of Units:	98.77
EE Technology Life:	10
Start Year:	2005
Incremental Costs:	-1777.86
Discount Factor:	8.56%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	10%
TRC NPV:	$32.79
Y/E CDM Reported TRC:	$17,942.30
Difference:	-$17,909.52
Reason for Difference:	Study period adjusted to 10 years from 20 years
	Calculations were based on new OPA tables
Note	TRC calcs based on number of units in HCHs calcs - discrepancy with y/e report

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
Outdoor Lighting Timers	1,778	1,811	33	1.02	2	3,654	4,059	0	0	10%	99	10
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Outdoor Lighting Timers	Urban	2,016	2,240	0	0	10%	0.03150		57	0	55	10
	Suburban	1,637	1,819	0	0	10%	0.03170		47	0	44	10
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Outdoor Lighting Timers	Urban	2,016	2,240	0	0	10%	0.03180		64	0	55	10
	Suburban	1,637	1,819	0	0	10%	0.03200		52	0	44	10
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Outdoor Lighting Timers	Urban	2,016	2,240	0	0	10%	0.03130		63	0	55	10
	Suburban	1,637	1,819	0	0	10%	0.03150		52	0	44	10
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Outdoor Lighting Timers	Urban	2,016	2,240	0	0	10%	0.03130		63	0	55	10
	Suburban	1,637	1,819	0	0	10%	0.03150		52	0	44	10
Commercial												
Industrial												

Assumptions:	2005
Programs:	Lighten Your Electricity Bill - Programmable Thermostat
OPA Table Applied:	Residential
Element No.:	88
Number of Units	141
EE Technology Life:	18
Start Year:	2005
Incremental Costs:	-7614
Discount Factor:	8.56%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	10%
TRC NPV:	$18,184.97
Y/E CDM Reported TRC:	$27,001.69
Difference:	-$8,816.72
	Space heating/cooling table elements combined into 1 in OPA tables
Reason for Difference:	Free ridership per OPA tables applied
	Calculations were based on new OPA tables

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
Programmable Thermostat	7,614	25,799	18,185	3.39	909	20,188	22,431	21	23	10%	141	18
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Programmable Thermostat	Urban	11,142	12,380	11	13	10%	0.03150		315	0	78	18
	Suburban	9,046	10,051	9	10	10%	0.03170		258	0	63	18
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Programmable Thermostat	Urban	11,142	12,380	11	13	10%	0.03180		353	0	78	18
	Suburban	9,046	10,051	9	10	10%	0.03200		289	0	63	18
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Programmable Thermostat	Urban	11,142	12,380	11	13	10%	0.03130		351	0	78	18
	Suburban	9,046	10,051	9	10	10%	0.03150		286	0	63	18
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Programmable Thermostat	Urban	11,142	12,380	11	13	10%	0.03130		349	0	78	18
	Suburban	9,046	10,051	9	10	10%	0.03150		285	0	63	18
Commercial												
Industrial												

APPENDIX B

LRAM and SSM Supporting Material
2006 Co-Branded Mass Market

98 Archibald Road, RR2, Kettleby, Ontario, L0G 1J0
Phone: 905.939.8239 Fax: 905.939.4606
Web: www.enerspectrum.com

Assumptions:	2006
Program:	Co-Branded Mass Market - Cold Water Washing
OPA Table Applied:	Residential
Element No.:	20
Number of Units:	601
EE Technology Life:	1
Start Year:	2006
Incremental Costs:	-4507.5
Discount Factor:	7.52%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	25%
TRC NPV:	$13,220.37
Y/E CDM Reported TRC:	$13,500.00
Difference:	-$279.63
Reason for Difference:	N/A since no TRC was provided to match y/e reported NPV
	Calculations were based on new OPA tables

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
Cold Water Washing (Detergent)	4,508	17,728	13,220	3.93	661	280,817	374,423	9	13	25%	601	1
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
Cold Water Washing (Detergent)	Urban	155,292	207,056	5	7	25%	0.03150		4,390	0	332	1
	Suburban	125,525	167,367	4	6	25%	0.03170		3,573	0	269	1
Commercial												
Industrial												

Assumptions:	2006
Programs:	Co-Branded Mass Market - LED christmas lights 5 Watt
OPA Table Applied:	Residential
Element No.:	35
Number of Units:	1000
EE Technology Life:	30
Start Year:	2006
Incremental Costs:	-1900
Discount Factor:	7.52%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	5%
TRC NPV:	$60,222.21
Y/E CDM Reported TRC:	$16,316.42
Difference:	$43,905.78
Reason for Difference:	Discount rate adjusted to 7.52% from 8.56%
	Calculations were based on new OPA tables

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
LED Christmas Lights (indoor or outdoor)	1,900	62,122	60,222	32.70	3,011	54,150	57,000	0	0	5%	1,000	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	29,945	31,521	0	0	5%	0.03150		846	0	553	30
	Suburban	24,205	25,479	0	0	5%	0.03170		689	0	447	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	29,945	31,521	0	0	5%	0.03180		949	0	553	30
	Suburban	24,205	25,479	0	0	5%	0.03200		772	0	447	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	29,945	31,521	0	0	5%	0.03130		942	0	553	30
	Suburban	24,205	25,479	0	0	5%	0.03150		766	0	447	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	29,945	31,521	0	0	5%	0.03130		937	0	553	30
	Suburban	24,205	25,479	0	0	5%	0.03150		762	0	447	30
Commercial												
Industrial												

Assumptions:	2006
Programs:	Co-Branded Mass Market - LED christmas lights Mini Watt
OPA Table Applied:	Residential
Element No.:	36
Number of Units:	1000
EE Technology Life:	30
Start Year:	2006
Incremental Costs:	-1900
Discount Factor:	7.52%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	5%
TRC NPV:	$5,847.31
Y/E CDM Reported TRC:	$5,071.72
Difference:	$775.59
Reason for Difference:	Discount rate adjusted to 7.52% from 8.56%

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
LED Christmas Lights (indoor or outdoor)	1,900	7,747	5,847	4.08	292	6,856	7,217	0	0	5%	1,000	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2006										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	3,791	3,991	0	0	5%	0.03150		107	0	553	30
	Suburban	3,065	3,226	0	0	5%	0.03170		87	0	447	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	3,791	3,991	0	0	5%	0.03180		120	0	553	30
	Suburban	3,065	3,226	0	0	5%	0.03200		98	0	447	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	3,791	3,991	0	0	5%	0.03130		119	0	553	30
	Suburban	3,065	3,226	0	0	5%	0.03150		97	0	447	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	3,791	3,991	0	0	5%	0.03130		119	0	553	30
	Suburban	3,065	3,226	0	0	5%	0.03150		97	0	447	30
Commercial												
Industrial												

APPENDIX C

LRAM and SSM Supporting Material
2007 Social Housing

98 Archibald Road, RR2, Kettleby, Ontario, L0G 1J0
Phone: 905.939.8239 Fax: 905.939.4606
Web: www.enerspectrum.com

Assumptions:	2007
Programs:	Co-Branded Mass Market - CFL 15W
OPA Table Applied:	Residential
Element No.:	24
Number of Units:	1400
EE Technology Life:	8
Start Year:	2007
Incremental Costs:	2520
Discount Factor:	7.52%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	10%
TRC NPV:	$26,300.53
Y/E CDM Reported TRC:	$131,553.21
Difference:	-$105,252.68
	Calculations were based on new OPA tables
Reason for Difference:	Study period adjusted to 8 years from 30 years
	starting year is 2007 instead of 2006

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
CFL Screw-in 15W	-2,520	23,606	26,126	9.37	1,306	54,432	60,480	1	1	10%	1,400	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 15W	Urban	15,099	33,554	1	1	10%	0.03180		479	0	777	8
	Suburban	12,117	26,926	1	1	10%	0.03200		387	0	623	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 15W	Urban	30,199	33,554	1	1	10%	0.03130		950	0	777	8
	Suburban	24,233	26,926	1	1	10%	0.03150		767	0	623	8
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
CFL Screw-in 15W	Urban	30,199	33,554	1	1	10%	0.03130		945	0	777	8
	Suburban	24,233	26,926	1	1	10%	0.03150		763	0	623	8
Commercial												
Industrial												

Assumptions:	2007
Programs:	Co-Branded Mass Market - LED christmas lights 5 Watt
OPA Table Applied:	Residential
Element No.:	35
Number of Units:	500
EE Technology Life:	30
Start Year:	2007
Incremental Costs:	-950
Discount Factor:	7.52%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	5%
TRC NPV:	$30,620.88
Y/E CDM Reported TRC:	$8,157.96
Difference:	$22,462.92
	starting year is 2007 instead of 2006
Reason for Difference:	Discount rate adjusted to 7.52% from 8.56%
	Calculations were based on new OPA tables

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
LED Christmas Lights (indoor or outdoor)	950	30,890	29,940	32.52	1,497	27,075	28,500	0	0	5%	500	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	15,021	15,812	0	0	5%	0.03180		476	0	277	30
	Suburban	12,054	12,688	0	0	5%	0.03200		385	0	223	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	15,021	15,812	0	0	5%	0.03130		473	0	277	30
	Suburban	12,054	12,688	0	0	5%	0.03150		382	0	223	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	15,021	15,812	0	0	5%	0.03130		470	0	277	30
	Suburban	12,054	12,688	0	0	5%	0.03150		380	0	223	30
Commercial												
Industrial												

Assumptions:	2007
Program:	Co-Branded Mass Market - LED christmas lights Mini Watt
OPA Table Applied:	Residential
Element No.:	36
Number of Units:	500
EE Technology Life:	30
Start Year:	2007
Incremental Costs:	-950
Discount Factor:	7.52%
LDC Costs:	summarized at portfolio level
Free Ridership Rate:	5%
TRC NPV:	$2,989.03
Y/E CDM Reported TRC:	$2,988.78
Difference:	$0.25
Reason for Difference:	Calculations were based on new OPA tables

Shared Savings Mechanism(SSM)

Rate Class	Total Costs k$ (NPV)	Total Benefits $ (NPV)	Net Benefits $ (NPV)	Benefit Cost Ratio	SSM Amount $	kWh Impact		kW Impact		Free Rider Rate	Number of Units	Program Duration Number Of Years
						Net	Gross	Net	Gross			
Residential												
LED Christmas Lights (indoor or outdoor)	950	3,854	2,904	4.06	145	3,428	3,608	0	0	5%	500	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2007										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	1,902	2,002	0	0	5%	0.03180		60	0	277	30
	Suburban	1,526	1,606	0	0	5%	0.03200		49	0	223	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2008										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	1,902	2,002	0	0	5%	0.03130		60	0	277	30
	Suburban	1,526	1,606	0	0	5%	0.03150		48	0	223	30
Commercial												
Industrial												

Lost Revenue Adjustment Mechanism (LRAM)

Rate Class		2009										
		kWh Impact		kW Impact		Free Rider Rate	Rate		Revenue $(000)		Number of Units	Program Duration Number Of Years
		Net	Gross	Net	Gross		$/kWh	$/kW	kWh Impact	kW Impact		
Residential												
LED Christmas Lights (indoor or outdoor)	Urban	1,902	2,002	0	0	5%	0.03130		60	0	277	30
	Suburban	1,526	1,606	0	0	5%	0.03150		48	0	223	30
Commercial												
Industrial												

APPENDIX D

LRAM and SSM Supporting Material
OPA Sponsored Programs 2006 and 2007

98 Archibald Road, RR2, Kettleby, Ontario, L0G 1J0
Phone: 905.939.8239 Fax: 905.939.4606
Web: www.enerspectrum.com

From: Bart Burman [bart.burman@enerspectrum.com]
Sent: Wednesday, July 22, 2009 11:24 AM
To: mrezazad@engmail.uwaterloo.ca
Subject: FW: 2006-8 OPA conservation program results - Haldimand County Hydro
Attachments: 2006-2008 OPA Conservation Results.Haldimand County Hydro Inc..xls

Bart Burman
Managing Partner
EnerSpectrum Group
www.enerspectrum.com
416 219 9976
From: Jane Albert [mailto:jalbert@hchydro.ca]
Sent: July-22-09 11:21 AM
To: Bart Burman
Subject: FW: 2006-8 OPA conservation program results - Haldimand County Hydro

From: Raegan Bunker [mailto:Raegan.Bunker@powerauthority.on.ca]
Sent: July-14-09 6:50 PM
To: Lloyd Payne; Jane Albert
Cc: James Yue; Chris Barker
Subject: 2006-8 OPA conservation program results - Haldimand County Hydro

Dear Lloyd and Jane,

I am pleased to provide you with the attached customized report which provides an estimated allocation of OPA-funded conservation program results for your service territory, from 2006, 2007 and 2008 programs. The spreadsheet-based report is structured according to the following tabs:

1. **Summary**: Provides a portfolio-level summary of the annual resources savings (MW and MWh, net and gross for each) for the 2006, 2007 and 2008 program portfolios. The summary includes both province wide results, as well as the estimated share of those results which occurred in your LDC service territory.
2. **Annual net demand savings – LDC**: Provides a stacked bar graph of the annual net summer peak demand savings (MW) that are estimated to occur within your service territory from 2006 through 2032, as a result of 2006, 2007 and 2008 programs.
3. **Annual net energy savings – LDC**: Provides a stacked bar graph of the annual net energy savings (MWh) that are estimated to occur within your service territory from 2006 through 2032, as a result of 2006, 2007 and 2008 programs.
4. **Annual net demand savings – Prov**: Provides a stacked bar graph of the annual net summer peak demand savings (MW) that are estimated to occur across the province from 2006 through 2032, as a result of 2006, 2007 and 2008 programs.
5. **Annual net energy savings – Prov**: Provides a stacked bar graph of the annual net energy savings (MWh) that are estimated to occur across the province from 2006 through 2032, as a result of 2006, 2007 and 2008 programs.
6. **Initiative level**: Provides a breakdown of the portfolio-level summary information provides in Summary tab, by individual initiative and year.
7. **Measures:** For each initiative in each year, this tab provides: per unit savings assumptions (summer peak demand savings, annual energy savings, effective useful life), net-to-gross adjustment factors, and participation numbers (provincial and estimated share for your LDC service territory).

8. **Local Distribution Companies**: includes the OEB-Year Book data that was used for results allocation amongst LDCs.

As described in my memo of July 3rd, the province wide program results have been broken out to individual LDC service territories using different methods depending on the specific initiative:

1. **LDC delivered programs**: savings were allocated based on participation data that was tracked by individual LDCs
2. **Third party (non-LDC delivered) programs**:
    a. Where LDC-specific geographic data on program participation was readily available, savings were allocated to corresponding LDC territory
    b. Where LDC-specific geographic data on program participation was not readily available, savings were allocated based on each LDC's share of the provincial energy consumption for the customer class targeted by the program, based on data from the OEB Yearbook of Electricity Distributors. The 2006 yearbook was used for 2006 programs; while the 2007 yearbook was used for both 2007 and 2008 programs, as the 2008 yearbook is not yet available.
3. **Programs run exclusively in Toronto**: all energy and demand savings were allocated to Toronto Hydro.

Please note that 2008 results are still preliminary and are subject to change. It is expected that LDCs will not publish or release the preliminary results. The preliminary results are based on participation numbers (reported by LDCs or other delivery agents for OPA programs) and program design assumptions regarding energy savings per participant and net-to-gross adjustment factors. A common and critical component of the Evaluation, Measurement & Verification (EM&V) process is the review and refinement of these upfront program input assumptions, which can ultimately have a significant impact on the final results.

If you would like to receive a copy of the third-party impact evaluation reports for 2007 program evaluations (Great Refrigerator Roundup, Cool Savings Rebate, Summer Savings and Every Kilowatt Counts) please send a request to james.yue@powerauthority.on.ca. We will communicate the results of our 2008 program evaluations, as soon as they are available.

We hope that you find this report both informative and useful, and that it meets your needs in any upcoming regulatory filings. If you have any questions, please do not hesitate to contact me.

Cheers
Raegan

Raegan Bunker
Manager, Conservation Portfolio

Ontario Power Authority
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OPA Conservation & Demand Management Programs

Annual Results

For: Haldimand County Hydro Inc.

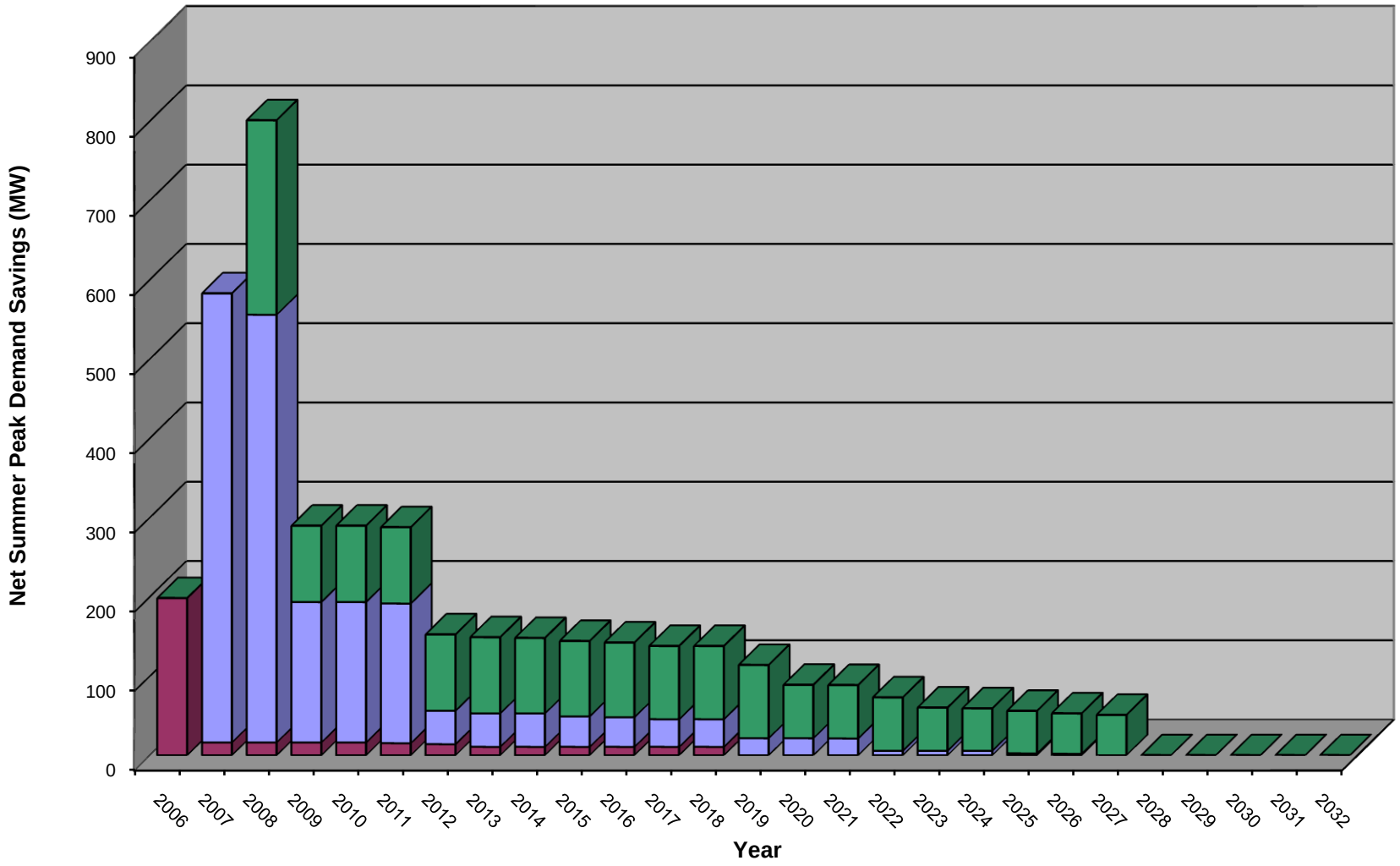
#	Program Name	Program Year	Results Status	Net Summer Peak Demand Savings (MW)																							
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Haldimand County Hydro Inc.	2006	Final	0.50	0.07	0.07	0.07	0.07	0.07	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Haldimand County Hydro Inc.	2007	Final	0.00	1.33	1.27	0.18	0.18	0.12	0.12	0.12	0.12	0.10	0.09	0.08	0.08	0.08	0.08	0.08	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Haldimand County Hydro Inc.	2008	Preliminary	0.00	0.00	0.53	0.29	0.29	0.29	0.29	0.29	0.28	0.28	0.28	0.27	0.27	0.27	0.17	0.17	0.17	0.12	0.12	0.12	0.11	0.11	0.00	0.00	0.00	0.00	0.00
Total				**0**	**1**	**2**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4	Province Wide	2006	Final	198.17	16.17	16.17	16.17	16.17	15.27	14.01	10.67	10.67	10.67	10.67	10.67	10.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Province Wide	2007	Final	0.00	566.38	539.51	177.11	177.11	176.15	42.13	42.13	42.13	38.33	37.30	34.83	34.83	21.50	21.50	21.19	5.66	5.63	5.63	2.46	1.95	0.00	0.00	0.00	0.00	0.00	0.00
6	Province Wide	2008	Preliminary	0.00	0.00	245.18	96.22	96.22	96.22	96.22	96.05	95.09	95.09	94.11	92.32	92.29	92.29	67.29	67.29	67.29	54.50	53.48	53.48	50.82	50.82	0.01	0.01	0.01	0.01	0.01
Total				**198**	**583**	**801**	**289**	**289**	**288**	**152**	**149**	**148**	**144**	**142**	**138**	**138**	**114**	**89**	**88**	**73**	**60**	**59**	**56**	**53**	**51**	**0**	**0**	**0**	**0**	**0**

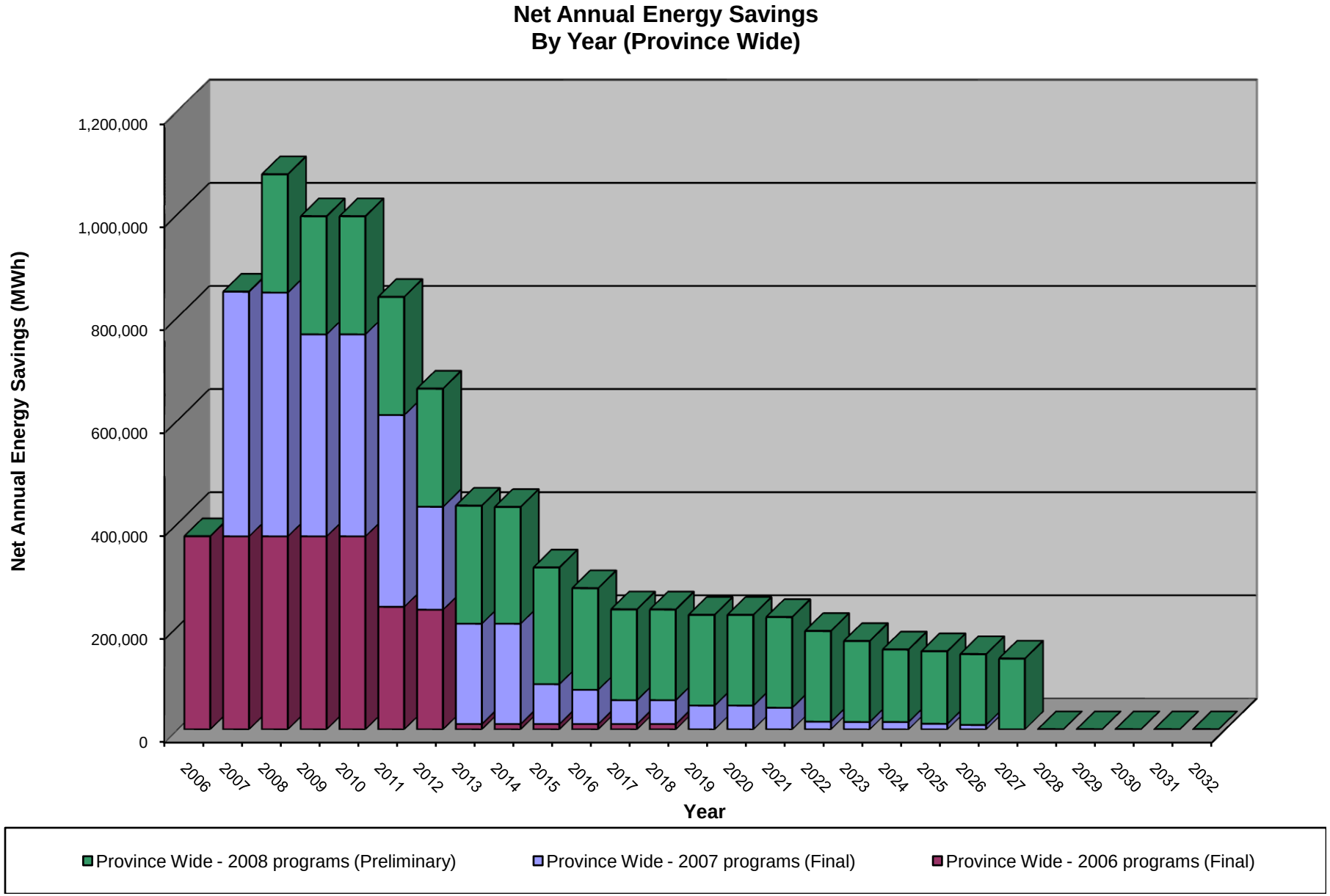
#	Program Name	Program Year	Results Status	Net Annual Energy Savings (MWh)																							
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Haldimand County Hydro Inc.	2006	Final	1,603	1,603	1,603	1,603	1,603	1,018	994	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Haldimand County Hydro Inc.	2007	Final	0	2,643	2,636	1,938	1,938	834	805	805	805	304	217	132	132	132	132	132	18	15	15	1	0	0	0	0	0	0	0
3	Haldimand County Hydro Inc.	2008	Preliminary	0	0	653	651	651	651	651	650	639	639	512	395	394	394	394	394	394	315	258	258	244	244	0	0	0	0	0
Total				**1,603**	**4,246**	**4,892**	**4,192**	**4,192**	**2,502**	**2,450**	**1,499**	**1,488**	**988**	**774**	**572**	**571**	**527**	**527**	**527**	**412**	**331**	**274**	**259**	**244**	**244**	**0**	**0**	**0**	**0**	**0**
4	Province Wide	2006	Final	374,407	374,407	374,407	374,407	374,407	237,735	232,140	10,417	10,417	10,417	10,417	10,417	10,417	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Province Wide	2007	Final	0	474,318	472,717	391,717	391,717	371,920	199,587	194,587	194,587	77,277	66,358	46,225	46,225	46,225	46,225	41,971	14,937	14,313	14,313	10,907	8,607	0	0	0	0	0	0
6	Province Wide	2008	Preliminary	0	0	229,237	228,869	228,869	228,869	228,869	228,705	226,154	226,154	196,889	175,929	175,690	175,690	175,690	175,690	175,690	156,885	140,437	140,437	137,155	137,155	47	47	47	47	47
Total				**374,407**	**848,725**	**1,076,360**	**994,993**	**994,993**	**838,524**	**660,596**	**433,709**	**431,158**	**313,848**	**273,664**	**232,570**	**232,332**	**221,915**	**221,915**	**217,661**	**190,627**	**171,198**	**154,750**	**151,344**	**145,762**	**137,155**	**47**	**47**	**47**	**47**	**47**

#	Program Name	Program Year	Results Status	Gross Summer Peak Demand Savings (MW)																							
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Haldimand County Hydro Inc.	2006	Final	0.71	0.08	0.08	0.08	0.08	0.07	0.07	0.05	0.05	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Haldimand County Hydro Inc.	2007	Final	0.00	4.29	4.23	0.29	0.29	0.23	0.20	0.20	0.20	0.17	0.15	0.14	0.14	0.14	0.14	0.14	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Haldimand County Hydro Inc.	2008	Preliminary	0.00	0.00	0.66	0.42	0.42	0.42	0.42	0.41	0.41	0.41	0.40	0.38	0.38	0.38	0.27	0.27	0.27	0.17	0.17	0.17	0.15	0.15	0.00	0.00	0.00	0.00	0.00
Total				**1**	**4**	**5**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4	Province Wide	2006	Final	283.96	17.96	17.96	17.96	17.96	16.97	15.56	11.86	11.86	11.86	11.86	11.86	11.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Province Wide	2007	Final	0.00	937.04	909.77	217.37	217.37	216.41	61.34	61.34	61.34	56.15	53.51	50.18	50.18	35.37	35.37	35.06	8.04	7.99	7.99	2.46	1.95	0.00	0.00	0.00	0.00	0.00	0.00
6	Province Wide	2008	Preliminary	0.00	0.00	283.17	133.78	133.78	133.78	133.78	133.40	132.02	132.02	130.45	126.47	126.44	126.44	98.66	98.66	98.66	75.03	73.34	73.34	68.72	68.72	0.01	0.01	0.01	0.01	0.01
Total				**284**	**955**	**1,211**	**369**	**369**	**367**	**211**	**207**	**205**	**200**	**196**	**189**	**188**	**162**	**134**	**134**	**107**	**83**	**81**	**76**	**71**	**69**	**0**	**0**	**0**	**0**	**0**

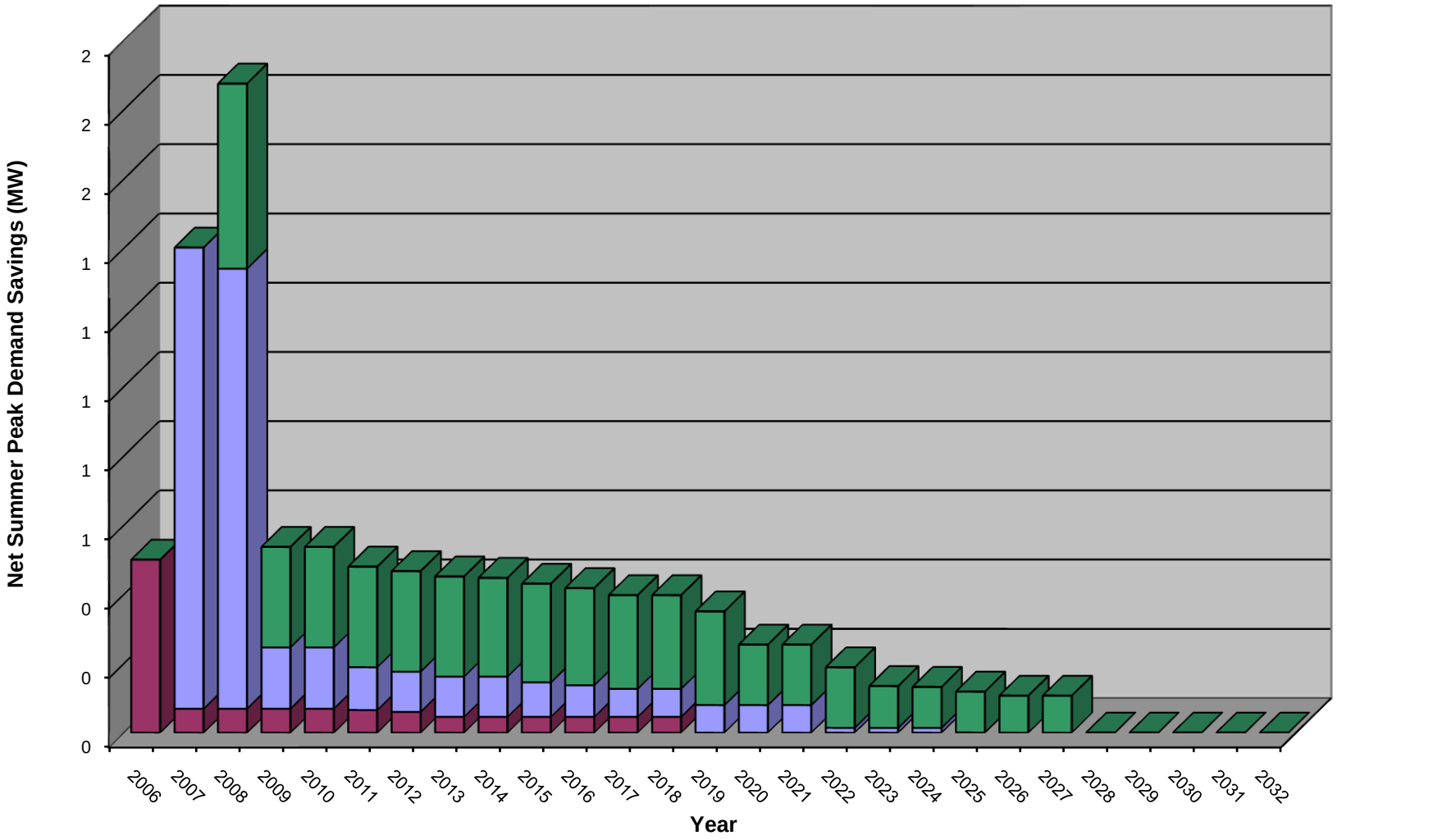
#	Program Name	Program Year	Results Status	Gross Annual Energy Savings (MWh)																							
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Haldimand County Hydro Inc.	2006	Final	1,781	1,781	1,781	1,781	1,781	1,131	1,104	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Haldimand County Hydro Inc.	2007	Final	0	8,269	8,256	2,436	2,436	1,332	1,223	1,223	1,223	565	342	230	230	230	230	230	30	25	25	1	0	0	0	0	0	0	0
3	Haldimand County Hydro Inc.	2008	Preliminary	0	0	1,043	1,040	1,040	1,040	1,040	1,037	1,022	1,022	861	603	601	601	601	601	601	459	355	355	334	334	0	0	0	0	0
Total				**1,781**	**10,049**	**11,080**	**5,257**	**5,257**	**3,503**	**3,367**	**2,309**	**2,294**	**1,636**	**1,253**	**882**	**880**	**831**	**831**	**831**	**631**	**484**	**380**	**356**	**334**	**334**	**0**	**0**	**0**	**0**	**0**
4	Province Wide	2006	Final	416,007	416,007	416,007	416,007	416,007	264,150	257,933	11,574	11,574	11,574	11,574	11,574	11,574	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Province Wide	2007	Final	0	1,189,858	1,186,946	511,946	511,946	492,149	277,077	277,077	277,077	123,786	95,856	69,231	69,231	69,231	69,231	64,977	17,763	16,629	16,629	10,907	8,607	0	0	0	0	0	0
6	Province Wide	2008	Preliminary	0	0	337,261	336,593	336,593	336,593	336,593	336,212	332,568	332,568	296,576	250,016	249,675	249,675	249,675	249,675	249,675	215,863	187,102	187,102	181,979	181,979	68	68	68	68	68
Total				**416,007**	**1,605,865**	**1,940,215**	**1,264,547**	**1,264,547**	**1,092,892**	**871,603**	**624,863**	**621,219**	**467,929**	**404,007**	**330,822**	**330,481**	**318,906**	**318,906**	**314,653**	**267,439**	**232,492**	**203,731**	**198,008**	**190,586**	**181,979**	**68**	**68**	**68**	**68**	**68**

Net Summer Peak Demand Savings By Year (Province Wide)

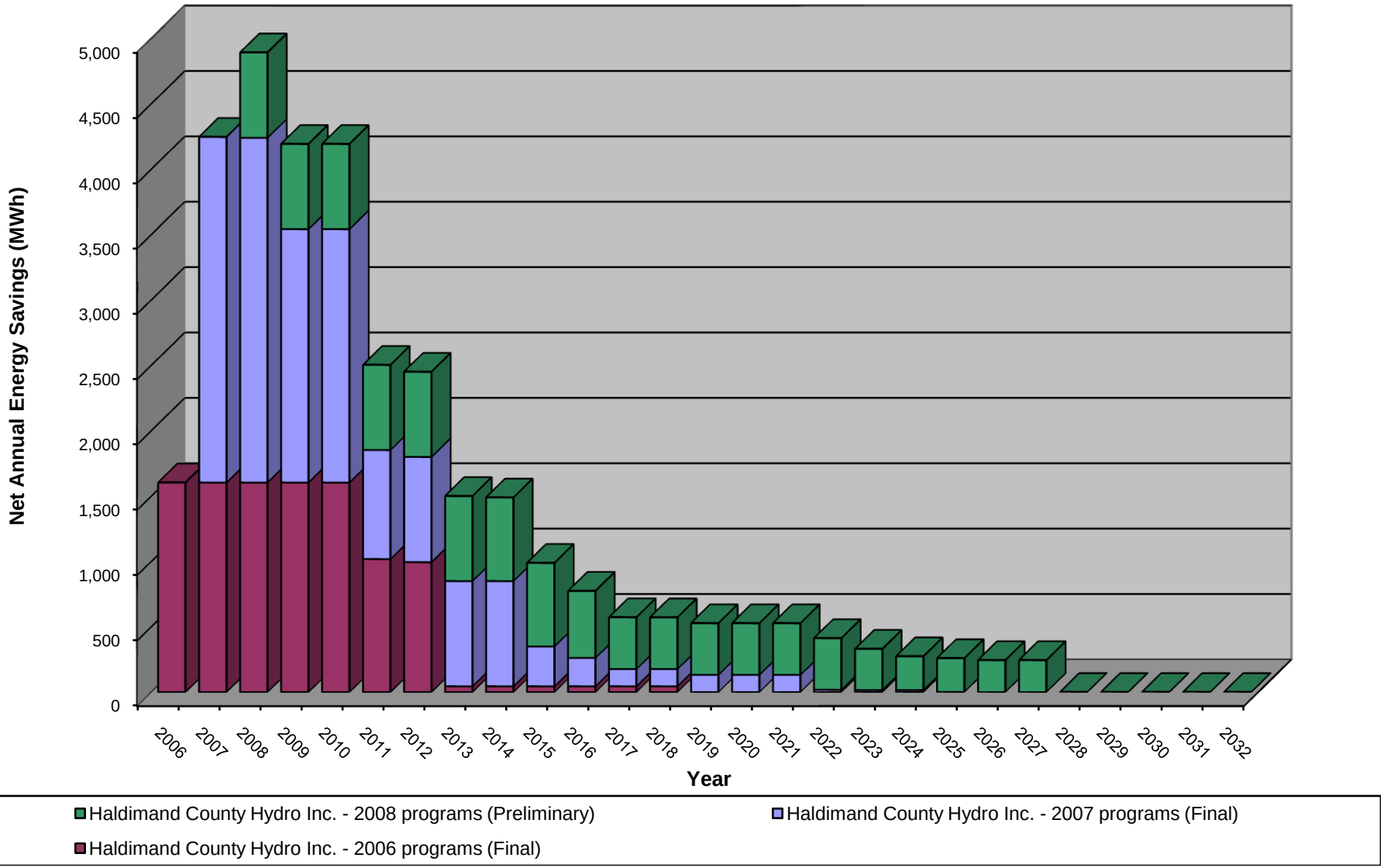



Net Annual Energy Savings
By Year (Province Wide)
Net Annual Energy Savings (MWh)
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
Year
Province Wide - 2008 programs (Preliminary)
Province Wide - 2007 programs (Final)
Province Wide - 2006 programs (Final)

Net Summer Peak Demand Savings By Year (LDC Specific)



Net Annual Energy Savings By Year (LDC Specific)



OPA Conservation & Demand Management Programs

Initiative Results

For: Haldimand County Hydro Inc.

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Summer Peak Demand Savings (MW)																							
						2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.00	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0.00	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0.00	0.39	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0.00	0.71	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007 Subtotal						**0**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	LDC Participation	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0.00	0.00	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	LDC Participation	0.00	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Overall Total						**0**	**1**	**2**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Haldimand County Hydro Inc.

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Annual Energy Savings (MWh)																							
						2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	585	585	585	585	585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	45	45	45	45	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	24	24	24	24	24	24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	949	949	949	949	949	949	949	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006 Subtotal						**1,603**	**1,603**	**1,603**	**1,603**	**1,603**	**1,018**	**994**	**45**	**45**	**45**	**45**	**45**	**45**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	103	103	103	103	103	102	102	102	87	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	128	128	128	128	128	123	123	123	123	123	123	123	123	123	123	12	12	12	0	0	0	0	0	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	1,104	1,104	1,104	1,104	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	559	552	552	552	552	528	528	528	43	43	8	8	8	8	8	5	2	2	0	0	0	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	698	698	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007 Subtotal						**0**	**2,643**	**2,636**	**1,938**	**1,938**	**834**	**805**	**805**	**805**	**304**	**217**	**132**	**132**	**132**	**132**	**132**	**18**	**15**	**15**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	LDC Participation	0	0	143	143	143	143	143	142	142	142	116	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0	0	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	8	8	8	0	0	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0	0	189	187	187	187	187	187	177	177	75	75	74	74	74	74	74	63	6	6	0	0	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	LDC Participation	0	0	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	0	0	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0	0	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	0	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008 Subtotal						**0**	**0**	**653**	**651**	**651**	**651**	**651**	**650**	**639**	**639**	**512**	**395**	**394**	**394**	**394**	**394**	**394**	**315**	**258**	**258**	**244**	**244**	**0**	**0**	**0**	**0**	**0**
Overall Total						**1,603**	**4,246**	**4,892**	**4,192**	**4,192**	**2,502**	**2,450**	**1,499**	**1,488**	**988**	**774**	**572**	**571**	**527**	**527**	**527**	**412**	**331**	**274**	**259**	**244**	**244**	**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Haldimand County Hydro Inc.

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Gross Summer Peak Demand Savings (MW)																							
						2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.00	0.17	0.17	0.17	0.17	0.17	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0.00	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0.00	3.23	3.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0.00	0.71	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007 Subtotal						**0**	**4**	**4**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	LDC Participation	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0.00	0.00	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0.00	0.00	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	LDC Participation	0.00	0.00	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Overall Total						**1**	**4**	**5**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Haldimand County Hydro Inc.

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Gross Annual Energy Savings (MWh)																							
						2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	650	650	650	650	650	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	50	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	27	27	27	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	1,055	1,055	1,055	1,055	1,055	1,055	1,055	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006 Subtotal						**1,781**	**1,781**	**1,781**	**1,781**	**1,781**	**1,131**	**1,104**	**50**	**50**	**50**	**50**	**50**	**50**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	259	259	259	259	259	256	256	256	223	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	243	243	243	243	243	215	215	215	215	215	215	215	215	215	215	21	21	21	0	0	0	0	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	1,104	1,104	1,104	1,104	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	791	779	779	779	779	700	700	700	76	76	14	14	14	14	14	8	3	3	0	0	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	5,820	5,820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007 Subtotal						**0**	**8,269**	**8,256**	**2,436**	**2,436**	**1,332**	**1,223**	**1,223**	**1,223**	**565**	**342**	**230**	**230**	**230**	**230**	**230**	**30**	**25**	**25**	**1**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	LDC Participation	0	0	312	312	312	312	312	309	309	309	259	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0	0	132	132	132	132	132	132	132	132	132	132	132	132	132	132	14	14	14	0	0	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	2007 LDC Residential Energy Throughput	0	0	264	261	261	261	261	261	246	246	137	137	135	135	135	135	135	111	8	8	0	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	LDC Participation	0	0	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0	0	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	LDC Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008 Subtotal						**0**	**0**	**1,043**	**1,040**	**1,040**	**1,040**	**1,040**	**1,037**	**1,022**	**1,022**	**861**	**603**	**601**	**601**	**601**	**601**	**601**	**459**	**355**	**355**	**334**	**334**	**0**	**0**	**0**	**0**	**0**
Overall Total						**1,781**	**10,049**	**11,080**	**5,257**	**5,257**	**3,503**	**3,367**	**2,309**	**2,294**	**1,636**	**1,253**	**882**	**880**	**831**	**831**	**831**	**631**	**484**	**380**	**356**	**334**	**334**	**0**	**0**	**0**	**0**	**0**

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Net Summer Peak Demand Savings (MW)																								
					2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	0.891	0.891	0.891	0.891	0.891	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	10.670	10.670	10.670	10.670	10.670	10.670	10.670	10.670	10.670	10.670	10.670	10.670	10.670	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	1.268	1.268	1.268	1.268	1.268	1.268	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	3.336	3.336	3.336	3.336	3.336	3.336	3.336	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	2006 Demand Response 1	Industrial, Business	2006	Final	182.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2006 Subtotal					**198**	**16**	**16**	**16**	**16**	**15**	**14**	**11**	**11**	**11**	**11**	**11**	**11**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0.000	1.544	1.544	1.544	1.544	1.544	1.361	1.361	1.361	1.035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	2007 Cool Savings Rebate	Consumer	2007	Final	0.000	19.820	19.820	19.820	19.820	19.820	18.689	18.689	18.689	18.689	18.689	18.689	18.689	18.689	18.689	18.689	3.154	3.154	3.154	0.000	0.000	0.000	0.000	0.000	0.000
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0.000	0.956	0.956	0.956	0.956	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0.000	5.070	4.594	4.594	4.594	4.594	4.594	4.594	4.594	1.118	1.118	0.045	0.045	0.045	0.045	0.045	0.045	0.017	0.017	0.000	0.000	0.000	0.000	0.000	0.000
11	2007 peaksaver®	Consumer, Business	2007	Final	0.000	13.322	13.322	13.322	13.322	13.322	13.322	13.322	13.322	13.322	13.322	13.322	13.322	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	2007 Summer Savings	Consumer	2007	Final	0.000	45.000	45.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0.000	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14	2007 Social Housing – Pilot	Consumer	2007	Final	0.000	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0.000	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.000	0.000	0.000	0.000	0.000	0.000
16	2007 Toronto Comprehensive	Business	2007	Final	0.000	130.900	130.900	130.900	130.900	130.900	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0.000	1.800	1.800	1.800	1.800	1.800	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18	2007 Demand Response 1	Industrial, Business	2007	Final	0.000	317.400	317.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19	2007 Other Demand Response	Industrial, Business	2007	Final	0.000	26.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0.000	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	0.000	0.000	0.000	0.000	0.000	0.000
2007 Subtotal					**0**	**566**	**540**	**177**	**177**	**176**	**42**	**42**	**42**	**38**	**37**	**35**	**35**	**22**	**22**	**21**	**6**	**6**	**6**	**2**	**2**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	0.000	0.000	2.495	2.495	2.495	2.495	2.495	2.329	2.329	2.329	1.793	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	0.000	0.000	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	14.426	2.613	2.613	2.613	0.000	0.000	0.000	0.000	0.000
23	2008 Aboriginal	Consumer	2008	Preliminary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	0.000	0.000	0.175	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	0.000	0.000	2.987	2.878	2.878	2.878	2.878	2.878	1.917	1.917	1.540	1.540	1.515	1.515	1.515	1.515	1.515	0.660	0.044	0.044	0.000	0.000	0.000	0.000	0.000
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	0.000	0.000	25.001	25.001	25.001	25.001	25.001	25.001	25.001	25.001	25.001	25.001	25.001	25.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	0.000	0.000	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	23.810	0.000	0.000	0.000	0.000
28	2008 Toronto Comprehensive	Business	2008	Preliminary	0.000	0.000	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	17.928	0.000	0.000	0.000	0.000
29	2008 High Performance New Construction	Business	2008	Preliminary	0.000	0.000	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.126	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	2008 Power Savings Blitz	Business	2008	Preliminary	0.000	0.000	0.472	0.472	0.472	0.472	0.472	0.472	0.472	0.472	0.407	0.407	0.407	0.407	0.407	0.407	0.407	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	0.000	0.000	0.030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	0.000	0.000	79.840	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	0.000	0.000	29.210	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0.000	0.000	39.600	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0.000	0.000	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	0.000	0.000	0.000	0.000
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0.000	0.000	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	0.000	0.000	0.000	0.000
2008 Subtotal					**0**	**0**	**245**	**96**	**96**	**96**	**96**	**96**	**95**	**95**	**94**	**92**	**92**	**92**	**67**	**67**	**67**	**54**	**53**	**53**	**51**	**51**	**0**	**0**	**0**	**0**	**0**
Overall Total					**198**	**583**	**801**	**289**	**289**	**288**	**152**	**149**	**148**	**144**	**142**	**138**	**138**	**114**	**89**	**88**	**73**	**60**	**59**	**56**	**53**	**51**	**0**	**0**	**0**	**0**	**0**

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Net Annual Energy Savings (MWh)																							
					2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	136,672	136,672	136,672	136,672	136,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	10,417	10,417	10,417	10,417	10,417	10,417	10,417	10,417	10,417	10,417	10,417	10,417	10,417	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	5,595	5,595	5,595	5,595	5,595	5,595	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	221,723	221,723	221,723	221,723	221,723	221,723	221,723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	2006 Demand Response 1	Industrial, Business	2006	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006 Subtotal					**374,407**	**374,407**	**374,407**	**374,407**	**374,407**	**237,735**	**232,140**	**10,417**	**10,417**	**10,417**	**10,417**	**10,417**	**10,417**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0	13,539	13,539	13,539	13,539	13,539	13,460	13,460	13,460	10,919	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	0	30,191	30,191	30,191	30,191	30,191	29,153	29,153	29,153	29,153	29,153	29,153	29,153	29,153	29,153	29,153	2,888	2,888	2,888	0	0	0	0	0	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0	19,797	19,797	19,797	19,797	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0	132,041	130,440	130,440	130,440	130,440	124,914	124,914	124,914	10,145	10,145	1,912	1,912	1,912	1,912	1,912	1,142	518	518	0	0	0	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	0	81,000	81,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	0	0	0	0	0	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	0	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	0	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	0	165,690	165,690	165,690	165,690	165,690	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0	5,000	5,000	5,000	5,000	5,000	5,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	2007 Demand Response 1	Industrial, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	0	0	0	0	0	0	0
2007 Subtotal					**0**	**474,318**	**472,717**	**391,717**	**391,717**	**371,920**	**199,587**	**194,587**	**194,587**	**77,277**	**66,358**	**46,225**	**46,225**	**46,225**	**46,225**	**41,971**	**14,937**	**14,313**	**14,313**	**10,907**	**8,607**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	0	0	25,842	25,842	25,842	25,842	25,842	25,678	25,678	25,678	20,961	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	0	0	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	17,865	1,912	1,912	1,912	0	0	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	0	0	44,676	44,308	44,308	44,308	44,308	44,308	41,758	41,758	17,687	17,687	17,448	17,448	17,448	17,448	17,448	14,883	1,370	1,370	0	0	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	0	0	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	54,286	0	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Preliminary	0	0	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	50,256	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Preliminary	0	0	287	287	287	287	287	287	287	287	287	287	287	287	287	287	287	0	0	0	0	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	0	0	3,459	3,459	3,459	3,459	3,459	3,459	3,459	3,459	2,982	2,982	2,982	2,982	2,982	2,982	2,982	2,982	47	47	47	47	47	47	47	47	47
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0	0	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0	0	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	0	0	0	0	0
2008 Subtotal					**0**	**0**	**229,237**	**228,869**	**228,869**	**228,869**	**228,869**	**228,705**	**226,154**	**226,154**	**196,889**	**175,929**	**175,690**	**175,690**	**175,690**	**175,690**	**175,690**	**156,885**	**140,437**	**140,437**	**137,155**	**137,155**	**47**	**47**	**47**	**47**	**47**
Overall Total					**374,407**	**848,725**	**1,076,360**	**994,993**	**994,993**	**838,524**	**660,596**	**433,709**	**431,158**	**313,848**	**273,664**	**232,570**	**232,332**	**221,915**	**221,915**	**217,661**	**190,627**	**171,198**	**154,750**	**151,344**	**145,762**	**137,155**	**47**	**47**	**47**	**47**	**47**

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Gross Summer Peak Demand Savings (MW)																									
					2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	0.990	0.990	0.990	0.990	0.990	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	11.856	11.856	11.856	11.856	11.856	11.856	11.856	11.856	11.856	11.856	11.856	11.856	11.856	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	1.409	1.409	1.409	1.409	1.409	1.409	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	3.707	3.707	3.707	3.707	3.707	3.707	3.707	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	2006 Demand Response 1	Industrial, Business	2006	Final	266.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2006 Subtotal					**284**	**18**	**18**	**18**	**18**	**17**	**16**	**12**	**12**	**12**	**12**	**12**	**12**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0.000	3.790	3.790	3.790	3.790	3.790	3.365	3.365	3.365	2.648	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	2007 Cool Savings Rebate	Consumer	2007	Final	0.000	39.732	39.732	39.732	39.732	39.732	32.532	32.532	32.532	32.532	32.532	32.532	32.532	32.532	32.532	32.532	5.514	5.514	5.514	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0.000	0.956	0.956	0.956	0.956	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0.000	7.341	6.476	6.476	6.476	6.476	6.476	6.476	6.476	2.002	2.002	0.073	0.073	0.073	0.073	0.073	0.022	0.022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	2007 peaksaver®	Consumer, Business	2007	Final	0.000	14.802	14.802	14.802	14.802	14.802	14.802	14.802	14.802	14.802	14.802	14.802	14.802	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	2007 Summer Savings	Consumer	2007	Final	0.000	375.000	375.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0.000	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
14	2007 Social Housing – Pilot	Consumer	2007	Final	0.000	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0.000	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.503	0.000	0.000	0.000	0.000	0.000	0.000	0.000
16	2007 Toronto Comprehensive	Business	2007	Final	0.000	145.444	145.444	145.444	145.444	145.444	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0.000	2.000	2.000	2.000	2.000	2.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18	2007 Demand Response 1	Industrial, Business	2007	Final	0.000	317.400	317.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19	2007 Other Demand Response	Industrial, Business	2007	Final	0.000	26.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0.000	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	1.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2007 Subtotal					**0**	**937**	**910**	**217**	**217**	**216**	**61**	**61**	**61**	**56**	**54**	**50**	**50**	**35**	**35**	**35**	**8**	**8**	**8**	**2**	**2**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	0.000	0.000	5.440	5.440	5.440	5.440	5.440	5.054	5.054	5.054	3.984	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	0.000	0.000	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	25.162	4.568	4.568	4.568	0.000	0.000	0.000	0.000	0.000	0.000
23	2008 Aboriginal	Consumer	2008	Preliminary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	0.000	0.000	0.501	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	0.000	0.000	6.039	5.841	5.841	5.841	5.841	5.841	4.468	4.468	4.063	4.063	4.027	4.027	4.027	4.027	4.027	1.177	0.057	0.057	0.000	0.000	0.000	0.000	0.000	0.000
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	0.000	0.000	27.779	27.779	27.779	27.779	27.779	27.779	27.779	27.779	27.779	27.779	27.779	27.779	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	0.000	0.000	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	34.014	0.000	0.000	0.000	0.000	0.000	0.000
28	2008 Toronto Comprehensive	Business	2008	Preliminary	0.000	0.000	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	25.612	0.000	0.000	0.000	0.000	0.000	0.000
29	2008 High Performance New Construction	Business	2008	Preliminary	0.000	0.000	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	2008 Power Savings Blitz	Business	2008	Preliminary	0.000	0.000	0.674	0.674	0.674	0.674	0.674	0.674	0.674	0.674	0.581	0.581	0.581	0.581	0.581	0.581	0.581	0.581	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	0.000	0.000	0.043	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	0.000	0.000	79.840	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	0.000	0.000	29.210	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0.000	0.000	39.600	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0.000	0.000	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	1.780	0.000	0.000	0.000	0.000	0.000	0.000
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0.000	0.000	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	7.300	0.000	0.000	0.000	0.000	0.000
2008 Subtotal					**0**	**0**	**283**	**134**	**134**	**134**	**134**	**133**	**132**	**132**	**130**	**126**	**126**	**126**	**99**	**99**	**99**	**75**	**73**	**73**	**69**	**69**	**0**	**0**	**0**	**0**	**0**
Overall Total					**284**	**955**	**1,211**	**369**	**369**	**367**	**211**	**207**	**205**	**200**	**196**	**189**	**188**	**162**	**134**	**134**	**107**	**83**	**81**	**76**	**71**	**69**	**0**	**0**	**0**	**0**	**0**

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Gross Annual Energy Savings (MWh)																								
					2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	151,857	151,857	151,857	151,857	151,857	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	6,217	6,217	6,217	6,217	6,217	6,217	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	246,359	246,359	246,359	246,359	246,359	246,359	246,359	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	2006 Demand Response 1	Industrial, Business	2006	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006 Subtotal					**416,007**	**416,007**	**416,007**	**416,007**	**416,007**	**264,150**	**257,933**	**11,574**	**11,574**	**11,574**	**11,574**	**11,574**	**11,574**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0	33,712	33,712	33,712	33,712	33,712	33,530	33,530	33,530	27,930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	0	57,469	57,469	57,469	57,469	57,469	50,864	50,864	50,864	50,864	50,864	50,864	50,864	50,864	50,864	50,864	5,050	5,050	5,050	0	0	0	0	0	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0	19,797	19,797	19,797	19,797	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0	187,163	184,252	184,252	184,252	184,252	165,622	165,622	165,622	17,932	17,932	3,206	3,206	3,206	3,206	3,206	1,807	673	673	0	0	0	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	0	675,000	675,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	0	0	0	0	0	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	0	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	0	184,100	184,100	184,100	184,100	184,100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0	5,556	5,556	5,556	5,556	5,556	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	2007 Demand Response 1	Industrial, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	0	0	0	0	0	0	0
2007 Subtotal					**0**	**1,189,858**	**1,186,946**	**1,186,946**	**511,946**	**492,149**	**277,077**	**277,077**	**277,077**	**123,786**	**95,856**	**69,231**	**69,231**	**69,231**	**69,231**	**64,977**	**17,763**	**16,629**	**16,629**	**10,907**	**8,607**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	0	0	56,369	56,369	56,369	56,369	56,369	55,988	55,988	55,988	46,560	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	0	0	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	31,127	3,343	3,343	3,343	0	0	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Preliminary	0	0	62,502	61,834	61,834	61,834	61,834	61,834	58,190	58,190	32,307	32,307	31,966	31,966	31,966	31,966	31,966	26,348	1,780	1,780	0	0	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	0	0	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	77,552	0	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Preliminary	0	0	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	71,794	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Preliminary	0	0	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	0	0	0	0	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	0	0	4,942	4,942	4,942	4,942	4,942	4,942	4,942	4,942	4,261	4,261	4,261	4,261	4,261	4,261	4,261	4,261	68	68	68	68	68	68	68	68	68
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0	0	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	0	0	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	0	0	0	0	0
2008 Subtotal					**0**	**0**	**337,261**	**336,593**	**336,593**	**336,593**	**336,593**	**336,212**	**332,568**	**332,568**	**296,576**	**250,016**	**249,675**	**249,675**	**249,675**	**249,675**	**249,675**	**215,863**	**187,102**	**187,102**	**181,979**	**181,979**	**68**	**68**	**68**	**68**	**68**
Overall Total					**416,007**	**1,605,865**	**1,940,215**	**1,264,547**	**1,264,547**	**1,092,892**	**871,603**	**624,863**	**621,219**	**467,929**	**404,007**	**330,822**	**330,481**	**318,906**	**318,906**	**314,653**	**267,439**	**232,492**	**203,731**	**198,008**	**190,586**	**181,979**	**68**	**68**	**68**	**68**	**68**

OPA Conservation & Demand Management Programs

Measure Results

For: Haldimand County Hydro Inc.

#	Initiative Name	Program Name	Program Year	Results Status	#	Measure Name	Unit Savings Assumptions			Net-to-Gross Adjustments (%)						Provincial Total (# Units)	LDC Total (# Units)
							Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)	Effective Useful Life (EUL)	Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)		
2006																	
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	1	Energy Star® Compact Fluorescent Light Bulb	0.00	104	4	90%	100%	100%	100%	100%	90%	1,338,276	5,729
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2	Electric Timers	0.00	183	20	90%	100%	100%	100%	100%	90%	37,518	161
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	3	Programmable Thermostats	0.05	216	15	90%	100%	100%	100%	100%	90%	16,320	70
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	4	Energy Star® Ceiling Fans	0.01	141	20	90%	100%	100%	100%	100%	90%	12,415	53
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	1	Energy Star® Air Conditioner	0.36	351	14	90%	100%	100%	100%	100%	90%	14,393	62
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2	Programmable Thermostats	0.16	159	18	90%	100%	100%	100%	100%	90%	10,965	47
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	3	Air Conditioner Tune-Up	0.04	369	8	90%	100%	100%	100%	100%	90%	9,816	42
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	1	Refrigerator Retirement	0.27	1,200	6	90%	100%	100%	100%	100%	90%	5,018	21
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2	Freezer Retirement	0.20	900	6	90%	100%	100%	100%	100%	90%	217	1
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	1	Energy Star® Compact Fluorescent Light Bulb	0.00	104	4	90%	100%	100%	100%	100%	90%	1,984,267	8,494
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2	Seasonal Light Emitting Diode Light String	0.00	31	30	90%	100%	100%	100%	100%	90%	477,612	2,045
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	3	Programmable Thermostats	0.12	522	18	90%	100%	100%	100%	100%	90%	31,484	135
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	4	Dimmers	0.00	139	10	90%	100%	100%	100%	100%	90%	0	107
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	5	Indoor Motion Sensors	0.00	209	20	90%	100%	100%	100%	100%	90%	0	38
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	6	Programmable Basebaord Thermostats	0.00	1,466	18	90%	100%	100%	100%	100%	90%	1,875	8
6	2006 Demand Response 1	Industrial, Business	2006	Final	1	Voluntary Load Shedding Project	Custom	Custom	1	100%	100%	100%	100%	100%	100%	6	0
2007																	
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	1	Refrigerator	0.07	745	9	48%	100%	100%	81%	100%	39%	37,123	296
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	2	Freezer	0.07	515	8	50%	100%	100%	91%	100%	46%	10,652	63
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	3	Small Refrigerator	0.05	490	9	38%	100%	100%	79%	100%	30%	581	5
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	4	Small Freezer	0.04	339	8	38%	100%	100%	79%	100%	30%	325	2
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	5	Window Air Conditioner	0.56	240	5	43%	100%	100%	100%	100%	43%	758	11
8	2007 Cool Savings Rebate	Consumer	2007	Final	1	ENERGY STAR® Central Air Conditioner	0.17	152	18	52%	5%	100%	100%	100%	57%	33,178	140
8	2007 Cool Savings Rebate	Consumer	2007	Final	2	Programmable Thermostat	0.03	55	15	46%	0%	60%	100%	100%	27%	46,989	199
8	2007 Cool Savings Rebate	Consumer	2007	Final	3	Furnace with Electronically Commutated Motor	0.49	832	15	54%	5%	100%	100%	100%	59%	51,990	220
8	2007 Cool Savings Rebate	Consumer	2007	Final	4	Central Air Conditioning Tune Up	0.26	235	5	42%	0%	38%	100%	100%	16%	28,048	119
9	2007 Aboriginal – Pilot	Consumer	2007	Final	1	Consumer Retrofit Kit	0.04	900	4	100%	100%	100%	100%	100%	100%	21,997	1,227
10	2007 Every Kilowatt Counts	Consumer	2007	Final	1	15 W CFL	0.00	43	8	78%	100%	100%	100%	100%	78%	2,376,053	10,048
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2	20 W+ CFLs	0.00	62	8	78%	100%	100%	100%	100%	78%	386,799	1,636
10	2007 Every Kilowatt Counts	Consumer	2007	Final	3	Project Porchlight CFLs	0.00	43	8	76%	100%	100%	100%	100%	76%	500,000	2,114
10	2007 Every Kilowatt Counts	Consumer	2007	Final	4	Energy Star Ceiling Fan	0.00	90	10	55%	100%	100%	100%	100%	55%	19,166	81
10	2007 Every Kilowatt Counts	Consumer	2007	Final	5	Furnace Filter	0.01	38	1	55%	100%	100%	100%	100%	55%	77,226	327
10	2007 Every Kilowatt Counts	Consumer	2007	Final	6	Solar Lights	0.00	33	5	13%	100%	100%	100%	100%	13%	305,048	1,290
10	2007 Every Kilowatt Counts	Consumer	2007	Final	7	Outdoor Motion Sensor	0.00	160	10	55%	100%	100%	100%	100%	55%	30,516	129
10	2007 Every Kilowatt Counts	Consumer	2007	Final	8	Dimmer Switch	0.00	24	10	55%	100%	100%	100%	100%	55%	19,390	82
10	2007 Every Kilowatt Counts	Consumer	2007	Final	9	Energy Star Light Fixtures	0.01	123	16	55%	100%	100%	100%	100%	55%	9,229	39
10	2007 Every Kilowatt Counts	Consumer	2007	Final	10	SLEDs	0.00	14	5	49%	100%	100%	100%	100%	49%	629,498	2,662
10	2007 Every Kilowatt Counts	Consumer	2007	Final	11	T8	0.00	37	18	77%	100%	100%	100%	100%	77%	18,088	76
10	2007 Every Kilowatt Counts	Consumer	2007	Final	12	Programmable Thermostat	0.00	75	15	55%	100%	100%	100%	100%	55%	18,633	79
10	2007 Every Kilowatt Counts	Consumer	2007	Final	13	Power Bar with Timer	0.01	72	10	77%	100%	100%	100%	100%	77%	8,442	36
10	2007 Every Kilowatt Counts	Consumer	2007	Final	14	Lighting Control Devices	0.02	72	10	55%	100%	100%	100%	100%	55%	97,742	413
11	2007 peaksaver®	Consumer, Business	2007	Final	1	Residential Programmable Thermostat	0.63	0	12	90%	100%	100%	100%	100%	90%	12,360	1
11	2007 peaksaver®	Consumer, Business	2007	Final	2	Residential Air Conditioner Switch	0.63	0	12	90%	100%	100%	100%	100%	90%	3,733	1
11	2007 peaksaver®	Consumer, Business	2007	Final	3	Residential Water Heater Switch	0.30	0	12	90%	100%	100%	100%	100%	90%	10,364	0
11	2007 peaksaver®	Consumer, Business	2007	Final	4	Commercial Programmable Thermostat	4.00	0	12	90%	100%	100%	100%	100%	90%	167	0
11	2007 peaksaver®	Consumer, Business	2007	Final	5	Commercial Air Conditioner Switch	4.00	0	12	90%	100%	100%	100%	100%	90%	221	0
11	2007 peaksaver®	Consumer, Business	2007	Final	6	Commercial Water Heater Switch	0.30	0	12	90%	100%	100%	100%	100%	90%	9	0
12	2007 Summer Savings	Consumer	2007	Final	1	Household	0.44	787	2	12%	100%	100%	100%	100%	12%	858,039	7,398
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	1	1 - T8 32W w/EL ballast	0.01	30	14	100%	100%	100%	100%	100%	100%	174	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	2	2 - T8 32W w/EL ballast	0.02	46	14	100%	100%	100%	100%	100%	100%	328	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	3	Air-source Heat Pump - Split	6.08	4,437	14	100%	100%	100%	100%	100%	100%	4	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	4	Automated Controls for HVAC	0.00	18,565	14	100%	100%	100%	100%	100%	100%	154	0

#	Initiative Name	Program Name	Program Year	Results Status	#	Measure Name	Unit Savings Assumptions			Net-to-Gross Adjustments (%)						Provincial Total (# Units)	LDC Total (# Units)
							Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)	Effective Useful Life (EUL)	Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)		
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	5	Boiler	0.01	17	14	100%	100%	100%	100%	100%	100%	78	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	6	Ceiling Fan (common area)	0.00	7	14	100%	100%	100%	100%	100%	100%	11	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	7	Ceiling Fan (in-suite)	0.00	7	14	100%	100%	100%	100%	100%	100%	12	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	8	Central Air Conditioning System - Single	1.07	807	14	100%	100%	100%	100%	100%	100%	75	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	9	Central Air Conditioning System - Split	1.94	1,456	14	100%	100%	100%	100%	100%	100%	15	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	10	CFL Screw-In 15W - in suite	0.01	180	14	100%	100%	100%	100%	100%	100%	920	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	11	CFL Screw-In 25W - in suite	0.01	300	14	100%	100%	100%	100%	100%	100%	143	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	12	Dimmer Switch	0.00	139	14	100%	100%	100%	100%	100%	100%	68	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	13	Energy Star Clotheswasher	0.03	287	14	100%	100%	100%	100%	100%	100%	23	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	14	Energy Star Dishwasher	0.01	136	14	100%	100%	100%	100%	100%	100%	2	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	15	Energy Star Refrigerator	0.01	69	14	100%	100%	100%	100%	100%	100%	448	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	16	Flood Light, 26W Fluorescent Fixture	0.01	128	14	100%	100%	100%	100%	100%	100%	30	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	17	Front Loading Washing Machine	0.11	1,108	14	100%	100%	100%	100%	100%	100%	43	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	18	Furnace	0.02	25	14	100%	100%	100%	100%	100%	100%	36	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	19	Furnace with DC Motor	0.03	45	14	100%	100%	100%	100%	100%	100%	5	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	20	Ground-source Heat Pump	4.71	3,545	14	100%	100%	100%	100%	100%	100%	26	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	21	High Pressure Sodium	0.09	749	14	100%	100%	100%	100%	100%	100%	10	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	22	Motion Detector	0.00	209	14	100%	100%	100%	100%	100%	100%	35	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	23	Occupancy Sensors	0.00	209	14	100%	100%	100%	100%	100%	100%	163	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	24	Other CFL Screw-in Light (please specify)	0.01	383	14	100%	100%	100%	100%	100%	100%	1,902	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	25	Other Exterior Lighting (please specify)	0.01	160	14	100%	100%	100%	100%	100%	100%	34	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	26	Other Parking Garage Lighting (please specify)	0.05	442	14	100%	100%	100%	100%	100%	100%	104	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	27	Photo Sensors	0.00	292	14	100%	100%	100%	100%	100%	100%	6	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	28	Programmable Thermostat	0.01	631	14	100%	100%	100%	100%	100%	100%	57	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	29	Timer - Outdoor Light	0.00	292	14	100%	100%	100%	100%	100%	100%	19	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	30	Ventilating Fan (in-suite)	0.00	12	14	100%	100%	100%	100%	100%	100%	48	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	1	Custom Retrofit Projects	Custom	Custom	10	100%	100%	100%	100%	100%	100%	9,680	41
15	2007 Energy Efficiency Assistance for House	Consumer	2007	Final	1	Custom Retrofit Projects	Custom	Custom	19	100%	100%	100%	100%	100%	100%	544	2
16	2007 Toronto Comprehensive	Business	2007	Final	1	City of Toronto - Better Building Partnership Pro	Custom	Custom	5	90%	100%	100%	100%	100%	90%	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	2	Toronto Hydro - Business Incentive Program Pr	Custom	Custom	5	90%	100%	100%	100%	100%	90%	24	0
16	2007 Toronto Comprehensive	Business	2007	Final	3	Building Owners & Managers Association - Toro	Custom	Custom	5	90%	100%	100%	100%	100%	90%	12	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	1	Custom Retrofit Projects	Custom	Custom	5	90%	100%	100%	100%	100%	90%	n/a	n/a
18	2007 Demand Response 1	Industrial, Business	2007	Final	1	Voluntary Load Shedding Project	Custom	Custom	2	100%	100%	100%	100%	100%	100%	16	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	1	Loblaw Contract	Custom	Custom	1	100%	100%	100%	100%	100%	100%	n/a	n/a
19	2007 Other Demand Response	Industrial, Business	2007	Final	2	Rodan Contract	Custom	Custom	1	100%	100%	100%	100%	100%	100%	n/a	n/a
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	1	Hydro	Custom	Custom	20	100%	100%	100%	100%	100%	100%	4	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	2	Wind	Custom	Custom	20	100%	100%	100%	100%	100%	100%	3	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	3	Solar Photo-Voltaic	Custom	Custom	20	100%	100%	100%	100%	100%	100%	72	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	4	Bio-Energy	Custom	Custom	20	100%	100%	100%	100%	100%	100%	2	0
2008																	
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	1	Refrigerator	0.06	745	9	56%	100%	100%	81%	100%	45%	62,327	346
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	2	Freezer	0.06	515	8	55%	100%	100%	91%	100%	50%	18,176	97
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	3	Small Refrigerator	0.04	490	9	38%	100%	100%	79%	100%	30%	299	2
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	4	Small Freezer	0.04	339	8	38%	100%	100%	79%	100%	30%	175	2
21	2008 Great Refrigerator Roundup	Consumer	2008	Preliminary	5	Window Air Conditioner	0.24	240	5	43%	100%	100%	100%	100%	43%	1,587	13
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	1	ENERGY STAR® Central Air Conditioner	0.21	155	18	52%	5%	100%	100%	100%	57%	21,537	91
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	2	Programmable Thermostat	0.04	54	15	46%	0%	60%	100%	100%	27%	27,493	116
22	2008 Cool Savings Rebate	Consumer	2008	Preliminary	3	Furnace with Electronically Commutated Motor	0.61	819	15	54%	5%	100%	100%	100%	59%	32,113	136
23	2008 Aboriginal	Consumer	2008	Preliminary	1	Building Retrofits	1.60	2,820	10	100%	100%	100%	100%	100%	100%	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Preliminary	1	Households	0.01	0	1	70%	100%	100%	100%	50%	35%	62,670	265
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	1	Energystar dehumidifiers - product amnesty & n	0.04	141	6	70%	100%	100%	100%	100%	70%	11,078	47
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	2	Energystar room air conditioners - product amne	0.08	192	6	70%	100%	100%	100%	100%	70%	10,837	46
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	3	T-8 Lighting	0.00	37	18	77%	100%	100%	100%	100%	77%	47,805	202
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	4	Energystar Lighting Fixtures	0.01	123	16	55%	100%	100%	100%	100%	55%	199,936	845
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	5	CFL Flood Lights (Outdoor)	0.00	77	8	93%	100%	100%	100%	100%	93%	213,379	902
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	6	CFL Flood Lights (Indoor)	0.00	44	8	93%	100%	100%	100%	100%	93%	213,378	902
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	7	Plugin pool/spa timer	0.97	1,158	15	30%	100%	100%	100%	100%	30%	2,953	12
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	8	Furance Filters - purchase of 2	0.01	38	1	55%	100%	100%	100%	100%	55%	17,702	75
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	9	Programmable Thermostats - Baseboard	0.00	30	15	70%	100%	100%	100%	100%	70%	21,808	92

#	Initiative Name	Program Name	Program Year	Results Status	#	Measure Name	Unit Savings Assumptions			Net-to-Gross Adjustments (%)						Provincial Total (# Units)	LDC Total (# Units)
							Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)	Effective Useful Life (EUL)	Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)		
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	10	Power Bar with Timer	0.01	72	10	70%	100%	100%	100%	100%	70%	4,710	20
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Preliminary	11	Block Heater Timer	0.00	180	15	70%	100%	100%	100%	100%	70%	8,630	36
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	1	Residential Programmable Thermostat	0.63	0	12	90%	100%	100%	100%	100%	90%	28,831	90
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	2	Residential Air Conditioner Switch	0.63	0	12	90%	100%	100%	100%	100%	90%	14,152	73
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	3	Residential Water Heater Switch	0.30	0	12	90%	100%	100%	100%	100%	90%	318	0
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	4	Commercial Programmable Thermostat	4.00	0	12	90%	100%	100%	100%	100%	90%	104	0
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	5	Commercial Air Conditioner Switch	4.00	0	12	90%	100%	100%	100%	100%	90%	47	1
26	2008 peaksaver®	Consumer, Business	2008	Preliminary	6	Commercial Water Heater Switch	0.30	0	12	90%	100%	100%	100%	100%	90%	1	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	1	Agribusiness ENERGY STAR® Rated Exit Signs	0.03	59	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	2	Agribusiness ENERGY STAR® Rated CFLs, Sc	0.04	101	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	3	Agribusiness ENERGY STAR® Rated CFLs, Ha	0.04	101	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	4	Agribusiness Standard Performance T8, Single	0.02	43	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	5	Agribusiness Standard Performance T8, Double	0.03	60	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	6	Agribusiness Standard Performance T8, Triple l	0.05	103	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	7	Agribusiness Standard Performance T8, Quadru	0.05	114	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	8	Agribusiness High Performance T8 (Consortium	0.02	48	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	9	Agribusiness High Performance T8 (Consortium	0.03	67	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	10	Agribusiness High Performance T8 (Consortium	0.05	103	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	11	Agribusiness High Performance T8 (Consortium	0.05	121	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	12	Agribusiness T5 Fixtures, T5 fixture with 1, 2, or	0.03	59	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	13	Agribusiness T5 Fixtures, High Bay T5. Maximu	0.03	75	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	14	Agribusiness Metal Halide, 320 W Ceramic puls	0.18	410	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	15	Agribusiness Occupancy Sensors, Switch plate	0.04	91	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	16	Agribusiness Occupancy Sensors, Ceiling moun	0.04	91	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	17	Agribusiness Creep Heat Pads, up to 100W max	0.08	171	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	18	Agribusiness Creep Heat Pads, up to 200W max	0.15	342	20	70%	100%	100%	100%	100%	70%	11	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	19	Agribusiness High Temperature Cutout Thermos	0.13	299	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	20	Agribusiness Creep Heat Controller	0.13	299	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	21	Agribusiness Energy Efficient Ventilation Exhau	0.05	119	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	22	Agribusiness Low Energy Livestock Waterers	0.70	1,596	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	23	Agribusiness Photocell and Timer for Lighting C	0.11	251	20	70%	100%	100%	100%	100%	70%	6	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	24	Lighting System Exit Signs, 5 W or less	0.03	59	20	70%	100%	100%	100%	100%	70%	4,629	35
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	25	Lighting System ENERGY STAR® Rated CFLs,	0.04	101	20	70%	100%	100%	100%	100%	70%	340,082	1,871
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	26	Lighting System ENERGY STAR® Rated CFLs,	0.04	101	20	70%	100%	100%	100%	100%	70%	16,236	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	27	Lighting System Standard Performance T8, Sing	0.02	43	20	70%	100%	100%	100%	100%	70%	16,557	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	28	Lighting System Standard Performance T8, Dou	0.03	60	20	70%	100%	100%	100%	100%	70%	79,625	421
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	29	Lighting System Standard Performance T8, Trip	0.05	103	20	70%	100%	100%	100%	100%	70%	5,184	153
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	30	Lighting System Standard Performance T8, Qua	0.05	114	20	70%	100%	100%	100%	100%	70%	28,832	199
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	31	Lighting System High Performance T8 (Consorti	0.02	48	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	32	Lighting System High Performance T8 (Consorti	0.03	67	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	33	Lighting System High Performance T8 (Consorti	0.05	103	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	34	Lighting System High Performance T8 (Consorti	0.05	121	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	35	Lighting System T5 Fixtures, T5 fixture with 1, 2	0.03	59	20	70%	100%	100%	100%	100%	70%	2,921	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	36	Lighting System T5 Fixtures, High Bay T5. Max	0.03	75	20	70%	100%	100%	100%	100%	70%	16,810	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	37	Lighting System Metal Halide, 320 W Ceramic p	0.18	410	20	70%	100%	100%	100%	100%	70%	274	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	38	Lighting System Occupancy Sensors, Switch pla	0.04	91	20	70%	100%	100%	100%	100%	70%	658	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	39	Lighting System Occupancy Sensors, Ceiling m	0.04	91	20	70%	100%	100%	100%	100%	70%	2,712	15
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	40	Motor Open Drip-Proof (ODP), 1 HP	0.02	46	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	41	Motor Open Drip-Proof (ODP), 1.5 HP	0.03	68	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	42	Motor Open Drip-Proof (ODP), 2 HP	0.04	91	20	70%	100%	100%	100%	100%	70%	2	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	43	Motor Open Drip-Proof (ODP), 3 HP	0.07	160	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	44	Motor Open Drip-Proof (ODP), 5 HP	0.07	160	20	70%	100%	100%	100%	100%	70%	15	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	45	Motor Open Drip-Proof (ODP), 7.5 HP	0.13	296	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	46	Motor Open Drip-Proof (ODP), 10 HP	0.15	342	20	70%	100%	100%	100%	100%	70%	15	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	47	Motor Open Drip-Proof (ODP), 15 HP	0.20	456	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	48	Motor Open Drip-Proof (ODP), 20 HP	0.26	593	20	70%	100%	100%	100%	100%	70%	4	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	49	Motor Open Drip-Proof (ODP), 25 HP	0.31	707	20	70%	100%	100%	100%	100%	70%	164	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	50	Motor Open Drip-Proof (ODP), 30 HP	0.33	752	20	70%	100%	100%	100%	100%	70%	2	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	51	Motor Open Drip-Proof (ODP), 40 HP	0.28	638	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	52	Motor Open Drip-Proof (ODP), 50 HP	0.48	1,094	20	70%	100%	100%	100%	100%	70%	3	0

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							Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)	Effective Useful Life (EUL)	Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)		
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	53	Motor Open Drip-Proof (ODP), 60 HP	0.53	1,208	20	70%	100%	100%	100%	100%	70%	2	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	54	Motor Open Drip-Proof (ODP), 75 HP	0.42	958	20	70%	100%	100%	100%	100%	70%	1	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	55	Motor Open Drip-Proof (ODP), 100 HP	0.81	1,847	20	70%	100%	100%	100%	100%	70%	3	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	56	Motor Open Drip-Proof (ODP), 125 HP	0.70	1,596	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	57	Motor Open Drip-Proof (ODP), 150 HP	0.74	1,687	20	70%	100%	100%	100%	100%	70%	1	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	58	Motor Open Drip-Proof (ODP), 200 HP	0.98	2,234	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	59	Motor Totally Enclosed Fan-Cooled (TEFC), 1 H	0.02	46	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	60	Motor Totally Enclosed Fan-Cooled (TEFC), 1.5	0.03	68	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	61	Motor Totally Enclosed Fan-Cooled (TEFC), 2 H	0.04	91	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	62	Motor Totally Enclosed Fan-Cooled (TEFC), 3 H	0.04	91	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	63	Motor Totally Enclosed Fan-Cooled (TEFC), 5 H	0.07	160	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	64	Motor Totally Enclosed Fan-Cooled (TEFC), 7.5	0.11	251	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	65	Motor Totally Enclosed Fan-Cooled (TEFC), 10	0.15	342	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	66	Motor Totally Enclosed Fan-Cooled (TEFC), 15	0.14	319	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	67	Motor Totally Enclosed Fan-Cooled (TEFC), 20	0.26	593	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	68	Motor Totally Enclosed Fan-Cooled (TEFC), 25	0.19	433	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	69	Motor Totally Enclosed Fan-Cooled (TEFC), 30	0.23	524	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	70	Motor Totally Enclosed Fan-Cooled (TEFC), 40	0.28	638	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	71	Motor Totally Enclosed Fan-Cooled (TEFC), 50	0.48	1,094	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	72	Motor Totally Enclosed Fan-Cooled (TEFC), 60	0.53	1,208	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	73	Motor Totally Enclosed Fan-Cooled (TEFC), 75	0.61	1,391	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	74	Motor Totally Enclosed Fan-Cooled (TEFC), 100	0.56	1,277	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	75	Motor Totally Enclosed Fan-Cooled (TEFC), 125	0.70	1,596	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	76	Motor Totally Enclosed Fan-Cooled (TEFC), 150	0.74	1,687	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	77	Motor Totally Enclosed Fan-Cooled (TEFC), 200	1.47	3,352	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	78	Transformer Size 15	0.15	345	20	70%	100%	100%	100%	100%	70%	1	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	79	Transformer Size 30	0.23	523	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	80	Transformer Size 45	0.24	546	20	70%	100%	100%	100%	100%	70%	26	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	81	Transformer Size 75	0.35	791	20	70%	100%	100%	100%	100%	70%	6	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	82	Transformer Size 112.5	0.44	1,012	20	70%	100%	100%	100%	100%	70%	1	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	83	Transformer Size 150	0.39	896	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	84	Transformer Size 225	0.50	1,147	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	85	Transformer Size 300	0.50	1,143	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	86	Transformer Size 500	0.83	1,902	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	87	Transformer Size 750	0.83	1,896	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	88	Transformer Size 1000	1.11	2,523	20	70%	100%	100%	100%	100%	70%	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	89	Unitary AC Single Phase <= 5.4 Tons	0.05	119	20	70%	100%	100%	100%	100%	70%	54	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	90	Unitary AC 3 Phase <= 5.4 Tons	0.05	119	20	70%	100%	100%	100%	100%	70%	79	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	91	Unitary AC >5.4 & <= 11.25 tons	0.13	287	20	70%	100%	100%	100%	100%	70%	292	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	92	Unitary AC >11.25 & <= 20 tons	0.18	408	20	70%	100%	100%	100%	100%	70%	166	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	93	Unitary AC 25 tons	1.00	2,280	20	70%	100%	100%	100%	100%	70%	83	0
27	2008 Electricity Retrofit Incentive	Business	2008	Preliminary	94	Custom	Custom	Custom	20	70%	100%	100%	100%	100%	70%	214	1
28	2008 Toronto Comprehensive	Business	2008	Preliminary	1	City of Toronto - Better Building Partnership Pro	Custom	Custom	20	70%	100%	100%	100%	100%	70%	2	0
28	2008 Toronto Comprehensive	Business	2008	Preliminary	2	Toronto Hydro - Business Incentive Program Pr	Custom	Custom	20	70%	100%	100%	100%	100%	70%	4	0
28	2008 Toronto Comprehensive	Business	2008	Preliminary	3	Building Owners & Managers Association - Toro	Custom	Custom	20	70%	100%	100%	100%	100%	70%	40	0
29	2008 High Performance New Construction	Business	2008	Preliminary	1	Custom New Construction Project	Custom	Custom	15	70%	100%	100%	100%	100%	70%	2	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	1	1 Lamp - 8' T12 w/ 75W Magnetic Ballasts to 2 L	0.02	146	16	70%	100%	100%	100%	100%	70%	8	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	2	1 Lamp - 8' T12 w/ 75W Magnetic Ballasts to 1 L	0.02	146	16	70%	100%	100%	100%	100%	70%	162	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	3	1 Lamp - 8' T12 w/ 75W Magnetic Ballasts to 2 L	0.02	146	16	70%	100%	100%	100%	100%	70%	54	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	4	2 Lamps - 8' T12 w/ 75W Magnetic Ballasts to 4	0.04	284	16	70%	100%	100%	100%	100%	70%	1,071	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	5	2 Lamps - 8' T12 w/ 75W Magnetic Ballasts to 2	0.07	497	16	70%	100%	100%	100%	100%	70%	737	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	6	2 Lamps - 8' T12 w/ 60W Magnetic Ballasts to 4	0.04	288	16	70%	100%	100%	100%	100%	70%	605	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	7	2 Lamps - 8' T12 w/ 60W Magnetic Ballasts to 2	0.07	504	16	70%	100%	100%	100%	100%	70%	286	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	8	1 Lamp - 4' T12 w/ 40W Magnetic Ballasts to 1 L	0.01	84	16	70%	100%	100%	100%	100%	70%	397	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	9	2 Lamps - 4' T12 w/ 40W Magnetic Ballasts to 1	0.03	232	16	70%	100%	100%	100%	100%	70%	77	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	10	2 Lamps - 4' T12 w/ 40W Magnetic Ballasts to 2	0.02	120	16	70%	100%	100%	100%	100%	70%	943	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	11	4 Lamps - 4' T12 w/ 40W Magnetic Ballasts to 2	0.06	468	16	70%	100%	100%	100%	100%	70%	198	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	12	4 Lamps - 4' T12 w/ 40W Magnetic Ballasts to 4	0.03	252	16	70%	100%	100%	100%	100%	70%	1,858	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	13	1 Lamp - 4' T12 w/ 34W Magnetic Ballasts to 1 L	0.01	72	16	70%	100%	100%	100%	100%	70%	131	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	14	2 Lamps - 4' T12 w/ 34W Magnetic Ballasts to 1	0.03	192	16	70%	100%	100%	100%	100%	70%	686	0

#	Initiative Name	Program Name	Program Year	Results Status	#	Measure Name	Unit Savings Assumptions			Net-to-Gross Adjustments (%)						Provincial Total (# Units)	LDC Total (# Units)
							Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)	Effective Useful Life (EUL)	Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)		
30	2008 Power Savings Blitz	Business	2008	Preliminary	15	2 Lamps - 4' T12 w/ 34W Magnetic Ballasts to 2	0.01	80	16	70%	100%	100%	100%	100%	70%	3,398	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	16	4 Lamps - 4' T12 w/ 34W Magnetic Ballasts to 2	0.05	392	16	70%	100%	100%	100%	100%	70%	3,224	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	17	4 Lamps - 4' T12 w/ 34W Magnetic Ballasts to 4	0.02	176	16	70%	100%	100%	100%	100%	70%	3,857	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	18	2 Lamps - U-Shaped w/ 40W Magnetic Ballasts	0.02	120	16	70%	100%	100%	100%	100%	70%	198	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	19	2 Lamps - U-Shaped w/ 40W Magnetic Ballasts	0.01	72	16	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	20	2 Lamps - U-Shaped w/ 34W Magnetic Ballasts	0.03	220	16	70%	100%	100%	100%	100%	70%	27	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	21	2 Lamps - U-Shaped w/ 34W Magnetic Ballasts	0.02	172	16	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	22	2 Lamps - 15W Incadescent Exit Sign to ENERG	0.03	236	25	70%	100%	100%	100%	100%	70%	184	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	23	2 Lamps - 15W Incadescent Exit Sign to Entire f	0.03	236	25	70%	100%	100%	100%	100%	70%	103	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	24	40W Standard Incandescent (A Lamp) to 11W E	0.02	116	8	70%	100%	100%	100%	100%	70%	91	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	25	60W Standard Incandescent (A Lamp) to 13W E	0.03	188	8	70%	100%	100%	100%	100%	70%	1,137	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	26	100W Standard Incandescent (A Lamp) to 23W	0.04	308	8	70%	100%	100%	100%	100%	70%	137	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	27	150W Standard Incandescent (A Lamp) to 28W	0.07	488	8	70%	100%	100%	100%	100%	70%	20	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	28	60W PAR38/30 Flood or Spot Recessed Lights	0.02	180	8	70%	100%	100%	100%	100%	70%	346	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	29	75W PAR38/30 Flood or Spot Recessed Lights	0.03	228	8	70%	100%	100%	100%	100%	70%	331	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	30	100W PAR38/30 Flood or Spot Recessed Lights	0.04	296	8	70%	100%	100%	100%	100%	70%	457	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	31	40 - 60W Standard Incandescent PAR Lights - T	0.02	180	8	70%	100%	100%	100%	100%	70%	328	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	32	40 - 60W Standard Halogen PAR Lights - Track	0.02	112	8	70%	100%	100%	100%	100%	70%	136	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	33	75W Standard Incandescent PAR Lights - Track	0.03	228	8	70%	100%	100%	100%	100%	70%	96	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	34	75W Standard Incandescent PAR Lights - Track	0.01	100	8	70%	100%	100%	100%	100%	70%	75	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	35	90 Watt Halogen PAR Lights - Track Lighting or	0.03	248	8	70%	100%	100%	100%	100%	70%	36	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	36	90 Watt Halogen PAR Lights - Track Lighting or	0.02	120	8	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	37	100W Standard Incandescent or Greater PAR L	0.04	296	8	70%	100%	100%	100%	100%	70%	64	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	38	100W Standard Incandescent or Greater PAR L	0.01	100	8	70%	100%	100%	100%	100%	70%	4	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	39	No Insulation Jacket (119 Gal) to Insulation Jac	0.00	0	6	70%	100%	100%	100%	100%	70%	16	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	40	No Insulation Jacket (80 Gal) to Insulation Jacke	0.00	0	6	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	41	No Insulation Jacket (65 Gal) to Insulation Jacke	0.00	0	6	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	42	No Insulation Jacket (50 Gal) to Insulation Jacke	0.00	0	6	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	43	No Insulation Jacket (40 Gal) to Insulation Jacke	0.00	0	6	70%	100%	100%	100%	100%	70%	37	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	44	No Insulation Jacket (30 Gal) to Insulation Jacke	0.00	0	6	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	45	No Insulation Jacket (20 Gal) to Insulation Jacke	0.00	0	6	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	46	No Insulation Jacket (12 Gal) to Insulation Jacke	0.00	0	6	70%	100%	100%	100%	100%	70%	0	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	47	No Pipe insulation to Pipe insulation (10 ft flexib	0.00	0	6	70%	100%	100%	100%	100%	70%	35	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	48	Aerator (Average 2.75gpm) to Aerator (Average	0.00	0	10	70%	100%	100%	100%	100%	70%	1	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	49	Authorized Contractor Program (ACP) - Work O	0.00	0	0	70%	100%	100%	100%	100%	70%	12	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	50	Authorized Contractor Program (ACP) - Work O	0.00	0	0	70%	100%	100%	100%	100%	70%	430	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	51	Authorized Contractor Program (ACP) - Work O	0.00	0	0	70%	100%	100%	100%	100%	70%	11	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	52	Contractor (Non-Classified Locations) - First 10	0.00	0	0	70%	100%	100%	100%	100%	70%	413	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	53	Contractor (Non-Classified Locations) - Each ad	0.00	0	0	70%	100%	100%	100%	100%	70%	445	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	54	4 Lamps - 8' T12 w/ 75W Magnetic Ballasts to 4	0.08	553	16	70%	100%	100%	100%	100%	70%	109	0
30	2008 Power Savings Blitz	Business	2008	Preliminary	55	Contractor (Non-Classified Locations) - Minimur	0.00	0	0	70%	100%	100%	100%	100%	70%	464	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	1	Mixed Use Facility	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	2	University Campus	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	3	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	3	Hospital	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	4	Commercial Office Tower	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	5	Industrial/Manufacturing Facility	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	6	City Government Central Utilities Plant	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Preliminary	7	Hotel	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
32	2008 Demand Response 1	Industrial, Business	2008	Preliminary	1	Voluntary Load Shedding Project	Custom	Custom	1	70%	100%	100%	100%	100%	70%	13	0
33	2008 Demand Response 3	Industrial, Business	2008	Preliminary	1	Contractual Load Shedding Project	Custom	Custom	1	100%	100%	100%	100%	100%	100%	10	0
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	1	Loblaw Contract	Custom	Custom	1	100%	100%	100%	100%	100%	100%	n/a	n/a
34	2008 Other Demand Response	Industrial, Business	2008	Preliminary	2	Rodan Contract	Custom	Custom	1	100%	100%	100%	100%	100%	100%	n/a	n/a
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	1	Hydro One Networks - Double Return - Distribut	130.77	0	1	100%	100%	100%	100%	100%	100%	117	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Preliminary	2	Hydro One Networks - Double Return - Transmi	8,100.00	0	1	100%	100%	100%	100%	100%	100%	3	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	1	Hydro	Custom	Custom	20	100%	100%	100%	100%	100%	100%	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	2	Wind	Custom	Custom	20	100%	100%	100%	100%	100%	100%	7	2
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	3	Solar Photo-Voltaic	Custom	Custom	20	100%	100%	100%	100%	100%	100%	116	1
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Preliminary	4	Bio-Energy	Custom	Custom	20	100%	100%	100%	100%	100%	100%	2	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Preliminary	1	Combined Heat & Power / By-Product	Custom	Custom	20	100%	100%	100%	100%	100%	100%	2	0

#	Local Distribution Company	2006 Residential Peak Load (kW)	2006 Residential Peak Load (%)	2006 Residential Energy Throughput (kWh)	2006 Residential Energy Throughput (%)	2006 Non-Residential Peak Load (kW)	2006 Non-Residential Peak Load (%)	2006 Non-Residential Energy Throughput (kWh)	2006 Non-Residential Energy Throughput (%)	2007 Residential Peak Load (kW)	2007 Residential Peak Load (%)	2007 Residential Energy Throughput (kWh)	2007 Residential Energy Throughput (%)	2007 Non-Residential Peak Load (kW)	2007 Non-Residential Peak Load (%)	2007 Non-Residential Energy Throughput (kWh)	2007 Non-Residential Energy Throughput (%)	2008 Residential Peak Load (kW)	2008 Residential Peak Load (%)	2008 Residential Energy Throughput (kWh)	2008 Residential Energy Throughput (%)	2008 Non-Residential Peak Load (kW)	2008 Non-Residential Peak Load (%)	2008 Non-Residential Energy Throughput (kWh)	2008 Non-Residential Energy Throughput (%)
1	Atikokan Hydro Inc	n/a	n/a	11,400,673	0.03%	n/a	n/a	34,099,588	0.04%	n/a	n/a	11,858,778	0.03%	n/a	n/a	31,082,191	0.04%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	Attawapiskat First Nation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3	Attawapiskat Power Corporation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4	Barrie Hydro Distribution Inc.	n/a	n/a	530,557,254	1.32%	n/a	n/a	937,360,428	1.20%	n/a	n/a	548,016,272	1.33%	n/a	n/a	940,740,837	1.14%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	Bluewater Power Distribution Corporation	n/a	n/a	261,470,152	0.65%	n/a	n/a	842,737,021	1.08%	n/a	n/a	264,836,003	0.64%	n/a	n/a	855,922,144	1.04%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6	Brant County Power Inc.	n/a	n/a	79,563,205	0.20%	n/a	n/a	145,133,733	0.19%	n/a	n/a	81,004,255	0.20%	n/a	n/a	207,717,221	0.25%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7	Brantford Power Inc.	n/a	n/a	284,501,278	0.71%	n/a	n/a	680,671,928	0.87%	n/a	n/a	298,531,289	0.73%	n/a	n/a	741,598,484	0.90%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8	Burlington Hydro Inc.	n/a	n/a	551,419,663	1.37%	n/a	n/a	1,182,280,000	1.51%	n/a	n/a	567,063,035	1.38%	n/a	n/a	1,199,736,238	1.45%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9	COLLUS Power Corp.	n/a	n/a	110,110,859	0.27%	n/a	n/a	225,767,061	0.29%	n/a	n/a	113,589,579	0.28%	n/a	n/a	215,072,148	0.26%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	Cambridge and North Dumfries Hydro Inc.	n/a	n/a	389,897,758	0.97%	n/a	n/a	1,175,499,726	1.50%	n/a	n/a	395,062,443	0.96%	n/a	n/a	1,165,105,313	1.41%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
11	Canadian Niagara Power Inc.	n/a	n/a	143,693,705	0.36%	n/a	n/a	215,257,881	0.27%	n/a	n/a	143,862,348	0.35%	n/a	n/a	215,810,521	0.26%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	Centre Wellington Hydro Ltd.	n/a	n/a	44,421,203	0.11%	n/a	n/a	104,851,041	0.13%	n/a	n/a	46,699,194	0.11%	n/a	n/a	111,831,932	0.14%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13	Chapleau Public Utilities Corporation	n/a	n/a	14,654,854	0.04%	n/a	n/a	13,456,323	0.02%	n/a	n/a	15,018,918	0.04%	n/a	n/a	13,186,691	0.02%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
14	Chatham-Kent Hydro Inc.	n/a	n/a	239,607,514	0.60%	n/a	n/a	615,842,408	0.79%	n/a	n/a	236,072,777	0.57%	n/a	n/a	601,416,856	0.73%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
15	Clinton Power Corporation	n/a	n/a	12,656,005	0.03%	n/a	n/a	5,883,572	0.01%	n/a	n/a	12,522,951	0.03%	n/a	n/a	18,085,796	0.02%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	Cooperative Hydro Embrun Inc.	n/a	n/a	19,799,972	0.05%	n/a	n/a	9,670,245	0.01%	n/a	n/a	19,386,628	0.05%	n/a	n/a	9,298,043	0.01%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
17	Cornwall Street Railway Light and Power Company Limited	n/a	n/a		0.00%	n/a	n/a	3,316,831	0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
18	Dubreuil Forest Products Ltd.	n/a	n/a		0.00%	n/a	n/a	104,680,214	0.13%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19	Dutton Hydro Limited	n/a	n/a	409,958	0.00%	n/a	n/a	244,729,136	0.31%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	E.L.K. Energy Inc.	n/a	n/a	91,182,112	0.23%	n/a	n/a	45,502,520	0.06%	n/a	n/a	94,171,770	0.23%	n/a	n/a	160,761,797	0.19%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	ENWIN Utilities Ltd.	n/a	n/a	655,143,475	1.63%	n/a	n/a	244,729,136	0.31%	n/a	n/a	664,998,752	1.62%	n/a	n/a	1,903,884,798	2.31%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	Enersource Hydro Mississauga Inc.	n/a	n/a	1,603,332,097	3.98%	n/a	n/a	6,490,116,773	8.28%	n/a	n/a	1,632,816,129	3.97%	n/a	n/a	6,605,288,225	8.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23	Erie Thames Powerlines Corporation	n/a	n/a	116,103,693	0.29%	n/a	n/a	36,572,686	0.05%	n/a	n/a	116,256,740	0.28%	n/a	n/a	291,852,488	0.35%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24	Espanola Regional Hydro Distribution Corporation	n/a	n/a	32,486,898	0.08%	n/a	n/a	30,450,548	0.04%	n/a	n/a	32,040,530	0.08%	n/a	n/a	31,021,479	0.04%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25	Essex Powerlines Corporation	n/a	n/a	284,492,550	0.71%	n/a	n/a	148,696,240	0.19%	n/a	n/a	280,966,066	0.68%	n/a	n/a	279,180,331	0.34%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	Festival Hydro Inc.	n/a	n/a	142,060,467	0.35%	n/a	n/a	471,908,335	0.60%	n/a	n/a	143,658,315	0.35%	n/a	n/a	468,128,577	0.57%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	Fort Albany First Nation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
28	Fort Albany Power Corporation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	Fort Frances Power Corporation	n/a	n/a	38,401,315	0.10%	n/a	n/a	42,879,081	0.05%	n/a	n/a	39,011,690	0.09%	n/a	n/a	43,615,480	0.05%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
30	Grand Valley Energy Inc	n/a	n/a	5,683,369	0.01%	n/a	n/a	2,812,411	0.00%	n/a	n/a	5,786,652	0.01%	n/a	n/a	3,568,735	0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
31	Great Lakes Power Limited	n/a	n/a	91,383,636	0.23%	n/a	n/a	102,068,591	0.13%	n/a	n/a	92,360,867	0.22%	n/a	n/a	109,854,997	0.13%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
32	Greater Sudbury Hydro Inc.	n/a	n/a	397,678,409	0.99%	n/a	n/a	535,059,474	0.68%	n/a	n/a	405,736,204	0.99%	n/a	n/a	543,747,565	0.66%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
33	Grimsby Power Incorporated	n/a	n/a	85,590,583	0.21%	n/a	n/a	18,314,103	0.02%	n/a	n/a	86,770,666	0.21%	n/a	n/a	88,449,813	0.11%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
34	Guelph Hydro Electric Systems Inc.	n/a	n/a	357,495,622	0.89%	n/a	n/a	1,264,636,266	1.61%	n/a	n/a	358,331,164	0.87%	n/a	n/a	1,269,317,570	1.54%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
35	Haldimand County Hydro Inc.	n/a	n/a	172,359,424	0.43%	n/a	n/a	185,282,283	0.24%	n/a	n/a	173,795,327	0.42%	n/a	n/a	183,754,191	0.22%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
36	Halton Hills Hydro Inc.	n/a	n/a	200,925,506	0.50%	n/a	n/a	271,457,391	0.35%	n/a	n/a	208,287,499	0.51%	n/a	n/a	311,739,725	0.38%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
37	Hearst Power Distribution Company Limited	n/a	n/a	26,681,677	0.07%	n/a	n/a	87,318,533	0.11%	n/a	n/a	28,317,089	0.07%	n/a	n/a	82,118,980	0.10%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
38	Horizon Utilities Corporation	n/a	n/a	1,654,664,050	4.11%	n/a	n/a	3,638,046,674	4.64%	n/a	n/a	1,666,789,557	4.06%	n/a	n/a	4,575,455,672	5.54%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
39	Hydro 2000 Inc.	n/a	n/a	15,223,723	0.04%	n/a	n/a	10,268,966	0.01%	n/a	n/a	15,036,848	0.04%	n/a	n/a	9,877,930	0.01%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
40	Hydro Hawkesbury Inc.	n/a	n/a	54,802,923	0.14%	n/a	n/a	143,819,890	0.18%	n/a	n/a	56,403,314	0.14%	n/a	n/a	145,226,883	0.18%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
41	Hydro One Brampton Networks Inc.	n/a	n/a	1,075,118,931	2.67%	n/a	n/a	2,744,176,570	3.50%	n/a	n/a	1,141,600,000	2.78%	n/a	n/a	2,798,700,000	3.39%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
42	Hydro One Networks Inc.	n/a	n/a	12,237,925,130	30.40%	n/a	n/a	9,935,112,037	12.68%	n/a	n/a	12,620,681,000	30.71%	n/a	n/a	10,298,799,000	12.47%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
43	Hydro One Networks Inc./Cat Lake Power Community	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
44	Hydro One Remote Communities Inc.	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
45	Hydro Ottawa Limited	n/a	n/a	2,226,415,669	5.53%	n/a	n/a	5,188,092,986	6.62%	n/a	n/a	2,234,039,085	5.44%	n/a	n/a	5,255,181,082	6.36%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
46	Innisfil Hydro Distribution Systems Limited	n/a	n/a	157,140,654	0.39%	n/a	n/a	28,964,493	0.04%	n/a	n/a	156,705,342	0.38%	n/a	n/a	71,986,330	0.09%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
47	Kashechewan First Nation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
48	Kashechewan Power Corporation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
49	Kenora Hydro Electric Corporation Ltd.	n/a	n/a	39,159,513	0.10%	n/a	n/a	68,402,801	0.09%	n/a	n/a	39,142,088	0.10%	n/a	n/a	70,186,402	0.08%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
50	Kingston Hydro Corporation	n/a	n/a	200,214,258	0.50%	n/a	n/a	531,028,042	0.68%	n/a	n/a	221,960,966	0.54%	n/a	n/a	497,012,043	0.60%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
51	Kitchener-Wilmot Hydro Inc.	n/a	n/a	644,108,007	1.60%	n/a	n/a	1,309,299,590	1.67%	n/a	n/a	660,550,766	1.61%	n/a	n/a	1,312,172,498	1.59%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
52	Lakefront Utilities Inc.	n/a	n/a	67,942,208	0.17%	n/a	n/a	213,381,240	0.27%	n/a	n/a	74,685,958	0.18%	n/a	n/a	215,906,659	0.26%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
53	Lakeland Power Distribution Ltd.	n/a	n/a	78,930,880	0.20%	n/a	n/a	45,933,794	0.06%	n/a	n/a	78,209,625	0.19%	n/a	n/a	135,514,735	0.16%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
54	London Hydro Inc.	n/a	n/a	1,088,755,114	2.70%	n/a	n/a	2,244,907,930	2.87%	n/a	n/a	1,117,183,048	2.72%	n/a	n/a	2,246,550,773	2.72%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
55	Middlesex Power Distribution Corporation	n/a	n/a	57,128,547	0.14%	n/a	n/a	145,163,360	0.19%	n/a	n/a	57,541,659	0.14%	n/a	n/a	139,592,176	0.17%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
56	Midland Power Utility Corporation	n/a	n/a	43,734,088	0.11%	n/a	n/a	177,618,443	0.23%	n/a	n/a	47,886,438	0.12%	n/a	n/a	175,517,601	0.21%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
57	Milton Hydro Distribution Inc.	n/a	n/a	197,466,598	0.49%	n/a	n/a	439,013,389	0.56%	n/a	n/a	218,633,202	0.53%	n/a	n/a	470,712,726	0.57%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
58	Newbury Power Inc.	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	463,355	0.00%	n/a	n/a	606,285	0.00%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
59	Newmarket - Tay Power Distribution Ltd.	n/a	n/a	262,995,579	0.65%	n/a	n/a	93,266,581	0.12%	n/a	n/a	270,904,453	0.66%	n/a	n/a	96,866,788	0.12%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
60	Niagara Peninsula Energy Inc.	n/a	n/a	449,386,643	1.12%	n/a	n/a	809,188,538	1.03%	n/a	n/a	423,910,347	1.03%	n/a	n/a	853,493,894	1.03%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
61	Niagara-on-the-Lake Hydro Inc.	n/a	n/a	63,805,148	0.16%	n/a	n/a	111,101,732	0.14%	n/a	n/a	65,561,722	0.16%	n/a	n/a	112,958,244	0.14%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
62	Norfolk Power Distribution Inc.	n/a	n/a	139,960,236	0.35%	n/a	n/a	237,962,119	0.30%	n/a	n/a	142,543,771	0.35%	n/a	n/a	236,960,151	0.29%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
63	North Bay Hydro Distribution Limited	n/a	n/a	207,199,584	0.51%	n/a	n/a	349,174,613	0.45%	n/a	n/a	213,131,701	0.52%	n/a	n/a	353,433,822	0.43%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
64	Northern Ontario Wires Inc.	n/a	n/a	43,040,214	0.11%	n/a	n/a	91,314,990	0.12%	n/a	n/a	43,226,412	0.11%	n/a	n/a	87,800,701	0.11%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
65	Oakville Hydro Electricity Distribution Inc.	n/a	n/a	569,566,301	1.41%	n/a	n/a	994,238,859	1.27%	n/a	n/a	592,214,968	1.44%	n/a	n/a	1,015,760,199	1.23%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
66	Orangeville Hydro Limited	n/a	n/a	79,376,454	0.20%	n/a	n/a	160,927,606	0.21%	n/a	n/a	80,135,717	0.19%	n/a	n/a	165,400,748	0.20%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
67	Orillia Power Distribution Corporation	n/a	n/a	108,206,276	0.27%	n/a	n/a	209,212,547	0.27%	n/a	n/a	109,590,116	0.27%	n/a	n/a	208,616,563	0.25%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
68	Oshawa PUC Networks Inc.	n/a	n/a	465,431,095	1.16%	n/a	n/a	632,361,055	0.81%	n/a	n/a	495,109,283	1.20%	n/a	n/a	685,818,845	0.83%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
69	Ottawa River Power Corporation	n/a	n/a	75,536,829	0.19%	n/a	n/a	116,088,912	0.15%	n/a	n/a	75,938,194	0.18%	n/a	n/a	84,784,890	0.10%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
70	PUC Distribution Inc.	n/a	n/a	335,395,539	0.83%	n/a	n/a	353,865,433	0.45%	n/a	n/a	338,874,337	0.82%	n/a	n/a	355,019,853	0.43%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
71	Parry Sound Power Corporation	n/a	n/a	33,103,725	0.08%	n/a	n/a	51,649,272	0.07%	n/a	n/a	34,279,947	0.08%	n/a	n/a	54,561,642	0.07%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
72	Peterborough Distribution Incorporated	n/a	n/a	290,645,501	0.72%	n/a	n/a	512,167,589	0.65%	n/a	n/a	286,683,602	0.70%	n/a	n/a	525,620,624	0.64%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
73	Port Colborne Hydro Inc.	n/a	n/a	63,748,755	0.16%	n/a	n/a	131,007,820	0.17%	n/a	n/a	65,276,304	0.16%	n/a	n/a	125,625,452	0.15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
74	PowerStream Inc.	n/a	n/a	2,003,371,840	4.98%	n/a	n/a	4,700,083,921	6.00%	n/a	n/a	2,039,498,572	4.96%	n/a	n/a	4,749,900,082	5.75%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
75	Renfrew Hydro Inc.	n/a	n/a	30,640,237	0.08%	n/a	n/a	65,574,034	0.08%	n/a	n/a	31,007,901	0.08%	n/a	n/a	67,121,871	0.08%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
76	Rideau St. Lawrence Distribution Inc.	n/a	n/a	44,343,815	0.11%	n/a	n/a	22,573,648	0.03%	n/a	n/a	45,086,486	0.11%	n/a	n/a	67,416,920	0.08%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
77	Sioux Lookout Hydro Inc.	n/a	n/a	31,452,628	0.08%	n/a	n/a	60,136,389	0.08%	n/a	n/a	32,814,076	0.08%	n/a	n/a	57,375,461	0.07%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
78	St. Thomas Energy Inc.	n/a	n/a	113,523,979	0.28%	n/a	n/a	250,600,744	0.32%	n/a	n/a	119,400,889	0.29%	n/a	n/a	244,392,868	0.30%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
79	Thunder Bay Hydro Electricity Distribution Inc.	n/a	n/a	346,415,246	0.86%	n/a	n/a	681,186,819	0.87%	n/a	n/a	344,508,404	0.84%	n/a	n/a	669,420,045	0.81%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
80	Tillsonburg Hydro Inc.	n/a	n/a	52,306,081	0.13%	n/a	n/a	175,367,100	0.22%	n/a	n/a	52,893,412	0.13%	n/a	n/a	183,570,981	0.22%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
81	Toronto Hydro-Electric System Limited	n/a	n/a	5,351,746,739	13.29%	n/a	n/a	20,069,911,519	25.61%	n/a	n/a	5,332,356,184	12.97%	n/a	n/a	20,316,766,672	24.60%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
82	Veridian Connections Inc.	n/a	n/a	929,432,918	2.31%	n/a	n/a	1,583,103,519	2.02%	n/a	n/a	960,984,164	2.34%	n/a	n/a	1,566,734,483	1.90%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
83	Wasaga Distribution Inc.	n/a	n/a	73,495,682	0.18%	n/a	n/a	31,661,531	0.04%	n/a	n/a	78,007,343	0.19%	n/a	n/a	35,464,935	0.04%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
84	Waterloo North Hydro Inc.	n/a	n/a	391,947,018	0.97%	n/a	n/a	922,560,313	1.18%	n/a	n/a	405,071,611	0.99%	n/a	n/a	954,721,743	1.16%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
85	Welland Hydro-Electric System Corp.	n/a	n/a	169,952,289	0.42%	n/a	n/a	314,737,340	0.40%	n/a	n/a	162,857,785	0.40%	n/a	n/a	300,569,977	0.36%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
86	Wellington North Power Inc.	n/a	n/a	25,536,958	0.06%	n/a	n/a	68,059,736	0.09%	n/a	n/a	25,027,983	0.06%	n/a	n/a	69,405,347	0.08%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
87	West Coast Huron Energy Inc.	n/a	n/a	27,222,139	0.07%	n/a	n/a	119,067,345	0.15%	n/a	n/a	26,672,783	0.06%	n/a	n/a	117,989,487	0.14%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
88	West Perth Power Inc.	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a	15,466,784	0.04%	n/a	n/a	46,047,710	0.06%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
89	Westario Power Inc.	n/a	n/a	207,243,931	0.51%	n/a	n/a	243,567,288	0.31%	n/a	n/a	213,039,032	0.52%	n/a	n/a	246,987,034	0.30%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
90	Whitby Hydro Electric Corporation	n/a	n/a	337,897,948	0.84%	n/a	n/a	511,216,232	0.65%	n/a	n/a	347,926,496	0.85%	n/a	n/a	511,966,838	0.62%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
91	Woodstock Hydro Services Inc.	n/a	n/a	104,833,112	0.26%	n/a	n/a	300,154,329	0.38%	n/a	n/a	104,412,330	0.25%	n/a	n/a	287,974,277	0.35%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total		**n/a**	**n/a**	**40,262,655,618**	**100.00%**	**n/a**	**n/a**	**78,355,367,185**	**100.00%**	**n/a**	**n/a**	**41,098,855,290**	**100.00%**	**n/a**	**n/a**	**82,578,437,108**	**100.00%**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

APPENDIX E

Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037

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Ontario Energy Board

Commission de l'énergie de l'Ontario

GUIDELINES FOR

ELECTRICITY DISTRIBUTOR

CONSERVATION AND DEMAND MANAGEMENT

EB-2008-0037

Date: March 28, 2008

GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT

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OVERVIEW

1.0 Background and Introduction

On May 31, 2004, the Minister of Energy granted approval to all distributors in Ontario to apply to the Ontario Energy Board (the "Board") for an increase in their 2005 rates by way of the third installment of their incremental market adjusted revenue requirement ("MARR"). This approval was conditional upon a commitment to reinvest in conservation and demand management ("CDM") an equivalent of one year's return. Consequently, in 2005 distributors brought forward, and the Board approved, $163 million in CDM funding for distributors, an amount related to the third tranche of their MARR.

The Board subsequently provided processes for distributors to apply for additional funding as part of the 2006 and 2007 distribution rate adjustment processes.

In its March 2, 2007 "Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond" (the "Framework Report") the Board confirmed its ongoing role in CDM activities by electricity distributors through the review and approval of spending levels and proposed programs, reporting guidelines, program evaluation, and the review and approval of applications for recovery of the Lost Revenue Adjustment Mechanism ("LRAM") and the Shared Savings Mechanism ("SSM"). The Board also reviews and approves claims for LRAM recovery associated with distributor CDM activities that are funded by the Ontario Power Authority (the "OPA").

Given this continued role, the Board believes it is important to set out its policies and guidelines on all aspects of CDM for electricity distributors that are within the scope of the Board's oversight on this issue. These Guidelines were developed in consultation with stakeholders to serve that purpose. They represent the consolidation of pre-existing and new policies, and reflect direction given by the Board in CDM-related decisions and orders.

Purpose

These Guidelines for Electricity Distributor Conservation and Demand Management (the "Guidelines") provide comprehensive information on the Board's policies relating to CDM activities undertaken by electricity distributors in Ontario. The policies set out in this document are intended to guide distributors in designing program proposals, applying to the Board for funding, and implementing their programs. They replace the policies and guidelines previously issued by the Board in respect of CDM activities by electricity distributors as articulated in the following documents:

- the Framework Report;
- the "Total Resource Cost Guide" issued in September, 2005; and

- the portions of the “Filing Requirements for Transmission and Distribution Applications” that pertain to CDM-related applications.

Nothing in these Guidelines replaces or supersedes any applicable requirements set out in any order of the Board.

With the exception of applications for LRAM recovery associated with OPA-funded CDM activities, the policies set out in the Guidelines apply only to CDM programs that are funded through distribution rates. Further, unless otherwise indicated, the policies set out in the Guidelines apply to all distribution-rate funded CDM activities, whether relating to the third installment of distributors’ incremental MARR, or through distribution rates approved in 2006 and beyond.

The Board expects that its policies will evolve over time, and the Guidelines will be updated accordingly.

THE POLICY FRAMEWORK

2.0 FUNDING OF CDM PROGRAMS

There are two streams of funding available to distributors for the delivery of CDM programs: funding from the OPA, and funding through distribution rates. The Guidelines discuss the funding available through distribution rates.

2.1 Funding Through Distribution Rates

The Board expects that most CDM funding for distributors will be provided by the OPA, either through the three-year fund of up to $400 million that was introduced by the government through the directive to the OPA on July 13, 2006,[1] or through other OPA initiatives. In 2007, the OPA provided funding to distributors for four standard programs.[2] It is expected that OPA funding will also be available to electricity distributors in 2008.

The Board remains of the view, however, that additional conservation resources could be provided by electricity distributors with continued funding through distribution rates.

Funding through distribution rates will therefore continue to be available for programs designed to address local CDM opportunities or other programs for which no OPA funding is available. Where funding for a particular program is not available from the OPA at the time of application, distributors may apply to the Board for funding through distribution rates. If funding from the OPA subsequently becomes available for a program which was approved through distribution rates, the Board expects the distributor to apply to the OPA for program funding to replace the distribution rate funding. This expectation applies equally where OPA funding for a distribution rate-funded program becomes available prior to the end of the term of a CDM plan.

In all cases, programs funded through distribution rates should be targeted to consumers within the distributor's licensed service area.

Whether and how CDM funding may be included in the incentive regulation mechanism rate adjustment is a rate-making matter than will be addressed in the appropriate forum.

2.1.1 Funding Term

The Board recognizes the benefits of multi-year funding, as it can reduce the year-over-year uncertainty regarding budget and program continuity that often comes with funding on a year-by-year basis. It may also allow distributors to better plan and manage the

[1] The directive issued to the OPA on July 13, 2006 instructed the OPA to organize the delivery and funding of CDM programs through Ontario distributors, and established a three-year fund of up to $400 million.
[2] Appliance Retirement, Business Incentive, Summer Savings, and Residential and Small Commercial Demand Response.

resources needed to deliver CDM programs, provide greater opportunity to monitor the success of programs, and facilitate the entering into of partnerships with other delivery agents.

Distributors may apply to the Board for funding for a period of up to three years. Budgets should be developed and measured on an annual basis within the multi-year plan. Annual budget amounts will be an input to each year's distribution rate adjustment.

While distributors may bring forward an application for funding at any time, the Board is of the view that such applications are best considered as part of a broader cost-of-service rate proceeding. This approach allows the Board and stakeholders to consider CDM amounts in conjunction with load forecasts, overall rate impacts, and any other activities that the distributor will be undertaking (e.g. system expansion).

Therefore, the Board encourages distributors to submit any requests for CDM funding as part of any cost-of-service application.

Distributors should submit a CDM plan, budget and evaluation plan[3] to the Board for review and approval. The budget should include cost estimates for administration, evaluation and support. Intervenors will have an opportunity to comment on the CDM plan, budget and evaluation plan.

Distributors should also file annual reports, as described in section 8.0.

Spending will be tracked in a CDM variance account, which will be used to "true-up" any variances between the spending estimate built into rates for the year and the actual spending in that year. It is expected that distributors will spend each year's annual budget in that year. However, there may be situations where this is not possible, for example, where customer uptake of the program has been slow. For plans with approved spending of more than one year, unspent funds can be carried over to a subsequent year. At the end of the approved funding term, any unspent funds will be returned to ratepayers through rates.

It is also possible that programs may be more successful than expected, such that the annual budget is insufficient. In this case, distributors may bring forward an application, with appropriate evidence and rationale, for recovery in rates of the amount spent in excess of the approved budget and tracked in the CDM variance account.

The additional spending may only be used for incremental program expenses. In order to recover these amounts in rates, a distributor should, at the time of its next cost-of-service application, provide appropriate evidence demonstrating the prudence and cost effectiveness of the amounts spent in excess of the approved annual budget. This is similar to the approach applicable to the gas utilities, as set out in the Board's Decision, dated August 25, 2006, on Phase I of the Generic DSM Proceeding.

[3] The Board's guidelines for an evaluation plan are set out in section 7.1 of the Guidelines.

As set out in above in section 2.1, if funding from the OPA subsequently becomes available for a program which was funded through distribution rates, the Board expects the distributor to apply to the OPA for funding for that program. In those circumstances, the CDM variance account will track the funding which was originally included in distribution rates so that it may be returned to customers. Alternatively, a distributor may apply to the Board to use the funding for another program which is not being funded by the OPA.

2.1.2 System Improvement Programs

The Board notes that there are currently no efficiency standards for distribution infrastructure, and as such, it is difficult to determine what component of a capital project could be characterized as "CDM". Further, the Board is of the view that maximizing efficiency of the distribution system should be part of prudent asset management practices, and not considered "extra" or "optional".

In the case of new infrastructure, or replacement of existing infrastructure, any measures to maximize the efficiency of the infrastructure will not be considered a CDM initiative. The Board expects that distributors will consider energy conservation and efficiency improvements as part of distributors' overall analysis of any infrastructure investment.

The Board is of the view that such an approach will better support conservation in Ontario.

Further, the Board notes that its planned initiative to develop appropriate distributor asset management practices will provide an opportunity to further explore the role of energy efficiency in asset management planning.

2.1.3 Pilot Programs

The Board considers a pilot program to be a program that involves the installation, testing or evaluation of technologies that are not already in use in Ontario, or in limited use, and that serves as a tentative model for future development.

The Board expects that a properly structured pilot should provide an opportunity to gain experience in business processes, installation procedures, logistics, deployment, integration issues, customer communications, and customer impacts. A distributor should provide a rationale for how its program will increase the collective understanding of the technology and its benefits as a CDM measure. Where the pilot program involves a non-cost effective technology, the onus will be on the distributor to prove the usefulness of the program. Distributors should be prepared to share the results and knowledge gained through the pilot with the Board and other distributors.

The Board does not consider it appropriate to have numerous distributors piloting the same technology or technology that has already been deployed within the Province.

Where a technology is already being, or has been, installed, tested or evaluated by another distributor, and a distributor wishes to implement a pilot program using the technology, the onus will be on the distributor to show how it will coordinate or work with the other distributor to ensure effective use of the program and of lessons learned.

Pilot programs involving smart metering, smart sub-metering and/or time of use pricing are subject to other legal and regulatory requirements that apply in addition to the provisions of these Guidelines.

3.0 COST EFFECTIVENESS

The Board has adopted the Total Resource Cost ("TRC") test as the appropriate test to measure cost effectiveness, and this test should be used by distributors when evaluating the cost effectiveness of CDM initiatives. The TRC test is defined as a test that "measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the [distributor's] costs".[4]

The TRC test measures the benefits and costs of CDM efforts from a societal perspective. Under the TRC test, benefits are driven by avoided resource costs, which are the marginal costs that are avoided by not producing and delivering the next unit of energy to the customer. Marginal costs (or avoided costs) include energy, generation, transmission and distribution costs. They measure the expected change in the systems total costs due to a decrease or increase in load and are calculated using either a short-run or long run perspective.

Costs in the TRC test are the costs of any equipment and program support costs associated with delivering that equipment to the marketplace.

Benefits	**Costs**[5]
Avoided electrical supply costs	Equipment costs
Other avoided resource costs	Distributor program costs

This section sets out the Board's expectations regarding the benefit-cost analysis for CDM programs. Additional information is provided in Appendix A.

3.1 TRC Calculation

Evaluating the cost effectiveness of CDM is done in stages at many different levels, including technology or measure, program, and portfolio. The TRC tests should be performed at each level.

At the most detailed level, a TRC test should be performed to evaluate the cost effectiveness of a measure or technology. Once a technology has proven to be cost effective, a program can be designed using that technology.[6] Once the program costs have been assessed, the TRC test will be performed again to evaluate the cost effectiveness of the program. Finally, several programs are bundled together, further indirect costs are included and the TRC test is carried out once again to evaluate the cost effectiveness of the portfolio. This three layered structure; technology or measure, program and portfolio, is key to performing TRC analyses.

[4] California Public Utilities Commission. (2001) Standard Practice Manual: Economic Analysis of Demand-Side Management Programs and Projects.
[5] In the case of fuel switching measures, the costs of the other fuels should be included.
[6] A distributor may deliver programs on non-cost effective technologies in the form of pilot programs , as set out in section 2.1.3 of the Guidelines.

The results of the TRC test should be expressed as a net present value (NPV). As a NPV assessment, the TRC test sums the streams of benefits and costs over the lifetime of the equipment/technology and uses a discount rate to express these streams as a single "current year" value. [7] Thus, the NPV_{TRC} is the net discounted value of the benefits and costs over a specified period of time (usually dictated by the equipment life of the CDM technology).

The TRC test is a measure of the change in the total resource costs to society, excluding externalities, of the CDM program. If the NPV_{TRC} is positive, indicating that benefits exceed costs, the program is considered cost effective from a societal perspective.

The TRC test examines streams of benefits and costs and uses discounting principles to express these future values as a single number.[8] The benefits stem from the avoided resource costs, typically electricity. The costs are the cost of the equipment and the distributor program costs. Subtracting the costs from the benefits provides the net benefits. For a program to be considered cost effective, the net benefits should be greater than zero.

3.2 TRC Benefits

3.2.1 Avoided Costs

As noted above, the TRC test assesses CDM costs and benefits from a societal perspective. The benefits are defined as "avoided costs". This represents the benefit to society of not having to provide an extra unit of supply – typically expressed as kW and/or kWh. For electricity, supply costs include energy, and generation, transmission and distribution capacity.

Certain CDM programs may have other benefits, including savings of other energy sources and/or water savings. While these savings are not the primary target of the program, the TRC test will accommodate an assessment of savings associated with avoiding the use of other resources including natural gas, heating fuel oil, propane or water. In these cases, the benefits accrue from the avoided costs associated with these resources. Distributors wishing to assess resource savings relating to other energy forms or water will need to use avoided cost estimates for those resources in the same manner that electricity avoided costs are used.

The TRC test involves an analysis over the life-cycle of the CDM measure. To accommodate this, long-term projections of avoided costs should also be undertaken. Also, any CDM measures included in the analysis should have equipment life estimates along with estimates of savings and costs.

[7] Discounting is a standard accounting principle which converts future monetary values into current values.
[8] The formula for this calculation is provided in Appendix A.

Not all of the avoided cost components and sub-components will be relevant for evaluating a particular CDM measure or program. For example, a program designed to shift load during peak hours may have little impact on annual energy use. Each potential CDM measure or program should be examined carefully to determine which types of loads will be avoided and which avoided costs apply.

Estimating the electrical avoided costs applicable to each customer class should include the following analytical steps:

1. estimate marginal generation costs of capacity and energy;
2. estimate marginal transmission costs;
3. estimate marginal distribution costs;
4. determine the appropriate costing periods; and
5. attribute marginal costs to the costing periods.

Marginal cost studies typically involve detailed analyses starting with an understanding of the current costs for generation, transmission and distribution. Capacity costs accommodate the costs of building and maintaining new generating plants and new transmission and distribution systems to meet increases in peak demand[9]. Energy costs measure the additional fuel and variable operating costs required to produce an extra kWh of energy. Energy costs can fluctuate on an hourly basis depending on the load level being served and the types of generating resources available in the market.

The avoided cost data that distributors should use for undertaking benefit-cost analyses of CDM measures and programs is posted on the Board's website. If a CDM measure contributes to the avoidance of distribution capacity costs, the distributor should include these avoided costs in its benefit-cost analysis. Information that may assist distributors in the determination of these avoided capacity costs has been included in the avoided cost information posted on the Board's website.

While all CDM measures can provide demand savings, only those measures which reduce load during peak seasons should apply capacity savings for generation, transmission and distribution. Since the Ontario load profile is summer peaking, only those measures which reduce load during the summer should apply the avoided cost of system capacity. However, since some distribution areas are winter peaking, measures which reduce winter load in those areas should include the value of avoided distribution capacity costs as one of the benefits.

3.2.2 Electrical Energy and Demand Savings

The benefits in the TRC test are driven by the annual energy (kWh/yr) and demand (kW) savings. Energy and demand savings are often calculated at the technology level and are commonly referred to as "prescriptive" savings estimates. For programs that

[9] "Peak demand" is defined as the maximum level of metered demand during a specified period.

rely on prescriptive savings estimates, savings are calculated by multiplying the per unit (i.e. single technology) savings with the number of units installed.

Savings and technology costs should be defined relative to a frame of reference or "base case". To accurately specify the impacts of any given technology, the analyst should know what would have happened in the absence of the technology. The base case technology variable represents the piece of equipment or technology that is being replaced by a more efficient technology. The application of a base case technology can vary, for example, in the case of a CDM program consisting of a residential programmable thermostat; the base technology would be a manual thermostat. In the example of a program consisting of a high efficiency furnace, the base case equipment would be the homeowner's current furnace. At a minimum, the base case technology should be equal to or more efficient than the technology benchmarks mandated in energy efficiency standards.

In practice, specifying savings relative to a frame of reference can be simply characterized by the three general decision types:

- new;
- replacement; or
- retrofit.

An example of how using a different base case can affect the energy savings estimates is provided in Appendix A.

In the TRC analysis, equipment life is used to determine the time period over which the net present value analysis is carried out. The equipment life variable represents the number of years that the more efficient equipment installed is assumed to produce energy savings. The benefits (i.e. energy and load savings) from an energy efficient piece of equipment are assumed to persist for the life of the equipment. Equipment life is estimated based on the nature of the equipment and an assumed usage pattern.

An important consideration when assessing equipment life is the potential difference between the energy efficient equipment and the "base case" equipment that is being replaced. A simplifying assumption in the case of replacement programs is that the energy efficient equipment lives are the same as in the base case. However, there are some technologies (such as lighting) where the energy efficient equipment may have a much longer life than the base case equipment. For example, a compact fluorescent bulb has an equipment life of up to 10,000 hours and would replace an incandescent bulb which has an equipment life of 1,000 hours. To accommodate this difference in the TRC analysis, the savings are assumed to persist for the entire 10,000 hours and the incremental cost should be adjusted to reflect the avoided purchase of 10 incandescent bulbs. This has the effect of enhancing the cost effectiveness of the compact fluorescent bulb measure.

The inputs and assumptions for a selection of measures, covering a range of typical CDM activities/technologies in residential, commercial and industrial applications are

posted on the Board's website. Distributors should use this data for undertaking benefit-cost analyses of CDM measures and programs.

Distributors may use other data, including free rider rates, where appropriate and justified. However, where a distributor uses other data, including other free rider rates, the distributor should provide detailed evidence to justify its use, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C.

3.3 TRC Costs

The TRC includes two types of CDM costs:

(1) equipment costs; and,
(2) program costs.

3.3.1 Equipment Costs

Typically in CDM programs, equipment costs are paid by the participant/customer. Customer equipment costs (sometimes termed "Participant costs") are the costs to purchase the more efficient equipment. They include both capital and operating and maintenance ("O&M") costs associated with the CDM program. It is important to note that the TRC test does not differentiate between who (distributor or customer) pays the cost of the equipment.

Customer costs can be incremental or full depending upon the nature of the energy efficiency investment decision. Incremental equipment costs are defined as the cost of the energy efficient technology above the base case technology. In the same way that the base case is important for specifying the savings, it is also important for specifying the cost of the energy efficient equipment. For example, in a replacement scenario, the cost of the energy efficient technology is typically incremental. In a retrofit or discretionary investment case, the cost of the energy efficient technology would be the full cost of the equipment.

Equipment costs, whether paid by the customer or the distributor, including purchase and installation, should always be defined relative to a base case. It is not enough to know the installed cost associated with the energy efficient equipment used in the program. To calculate the impact of the program, the cost of the equipment that would have been purchased in the absence of the program, the base case, should also be known. The appropriate specification of incremental cost for use in the TRC analysis is the difference between the base case and the energy efficient purchase.

An example of how costs will vary depending upon the base case assumption is provided in Appendix A.

As in the case of savings, there are typically three generic categories for specifying equipment costs, representing the type of investment decision:

- new;
- replacement; or,
- retrofit.

The information sources for equipment costs will vary. For residential equipment, retail store prices are appropriate sources of information for many technologies including lighting, appliances and "do-it-yourself" water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For commercial and industrial equipment, cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger "custom" projects, invoices or purchase orders may be necessary to support the cost estimate.

Equipment that requires O&M expenditures is often not incremental (i.e., those costs would have been incurred in the base case anyway). However, if the energy efficient equipment requires significantly more maintenance than its less energy efficient counterpart, the incremental O&M costs need to be factored into the TRC analysis. There will be exceptions and a proper TRC analysis should incorporate these.

3.3.2 Program Costs

From the perspective of the TRC test, CDM program costs are those incurred by the distributor. These costs include the marketing and support costs associated with delivering the CDM activity. Participant or customer incentive costs, which are considered transfers in the TRC test, are <u>not</u> included in the analysis.

Distributor costs typically cover a number of activities such as marketing and advertising, consulting, channel support, monitoring and evaluation. There are five major categories of distributor costs:

i. development and start-up;
ii. promotion;
iii. equipment and installation;
iv. monitoring and evaluation; and
v. administration.

In practice, all of these costs can be expected for programs that distributors in Ontario might be considering. For an accurate TRC assessment, the distributor should ensure that all costs associated with designing, operating and tracking the programs, other than incentive costs, are accounted for in its TRC analysis.

i. Development and Start-up Costs

Development and start-up costs are different from on-going operating costs. For example, initial costs may be incurred to train distributor staff in the use of the equipment or techniques used in a program and usually occur at the early stages of the program's life. Costs of developing CDM plans and procedures are also often

concentrated in the early program years. In general, start-up costs are only a small component of the total costs in the life cycle of a CDM program.

ii. Promotion Costs

Promotion costs may be incurred to educate the customer about a CDM program and will vary by program type and level of promotional effort. The cost of promotion depends on the method employed, the market segment and the CDM measures promoted. Program promotion may also involve trade-offs between increases in promotion costs and expected increases in participation.

Examples of methods of promotion are provided in Appendix A.

The appropriate costs to be included in the TRC analysis are the equipment and program delivery costs. Incentive payments from the distributor to a customer for participation in a program are not a component of the TRC analysis, but still should be included in the distributor's program budget. The incentive merely represents a transfer payment between two parties involved in the program.

Appendix A contains further information on distributor costs for incentives, and on why the incentive amount is not included in the TRC analysis.

iii. Distributor Equipment and Installation Costs

Distributor equipment and installation costs include the costs of any distributor devices needed to operate the programs such as specialized software or tools, as well as any equipment directly installed by the distributor such as load control devices.

iv. Monitoring and Evaluation Costs

This section focuses on the cost to the distributor of monitoring and evaluating a CDM portfolio.

There are two broad categories of evaluation activity: impact evaluation and process evaluation. Impact evaluation focuses on the specific impacts of the program – for example, savings and costs. Process evaluation focuses on the effectiveness of the program design – for example, the delivery channel. The costs associated with each of these activities are program costs that need to be included in the TRC analysis. Some of these costs will be assigned directly to a specific program or programs, while a portion of the costs are more appropriately assigned across all programs (i.e., at the CDM portfolio level).

Monitoring and evaluation costs are incurred for systems, equipment and studies necessary to track measurable levels of program success (participants, load impacts and costs) as well as to evaluate the features driving program success or failure. It is important to develop the necessary tracking systems at the time of program design. At

a minimum, the tracking system should collect information on the key components that drive the TRC test, including:

- number of participants/installations;
- energy and seasonal demand savings;
- cost of equipment; and
- distributor program costs.

To facilitate the evaluation of CDM programs and results, distributors should have clearly documented "paper trails".

v. Administrative costs

Administrative costs are generally the costs of staff who work on CDM activities. These costs are often differentiated between support and operations staff. Support staff costs are considered fixed costs or "overhead" that occur regardless of the level of customer participation in the programs. Operations staff costs are variable, depending on the level of customer participation. Distributors should include all staff salaries that are attributable to CDM programs as part of the costs in the TRC analysis.

3.4 Adjustment Factors in the TRC Test

In performing a TRC analysis, several adjustments should be made to the benefits side of the equation. These adjustments include:

- free ridership of participants (section 3.4.1);
- attribution of the benefits (section 3.4.2);
- persistence of the measures (section 3.4.3); and
- distribution and transmission losses (section 3.4.4).

3.4.1 Free Riders

Free rider adjustments are one of the key components of the TRC test. The standard definition of a free rider is "a program participant who would have installed a measure on his or her own initiative even without the program".[10] This participant simply uses the program to offset the cost of installing or undertaking the energy efficient initiative.

Costs and benefits associated with free ridership should be assessed as part of the TRC analysis. In determining overall savings, these participants are excluded from the benefits attributed to the program. The equipment costs associated with these participants is similarly excluded from cost side of the equation. [11] However, all program costs associated with free riders should be included in the analysis. Programs

[10] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs*. Report prepared for the International Energy Agency.
[11] Eto, J. (1998) *Guidelines for Assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives*. Northeast Energy Efficiency Partnership, Inc.

that have high free ridership are self-evident in the marketplace (i.e. they do not rely on a distributor promotion) and are less cost effective since the program costs are included in the TRC calculation while the benefits are not.

3.4.2 Attribution

CDM activities are managed and/or delivered not only by electricity distributors, but also by others such as gas distributors, electricity retailers, gas marketers and the OPA.

A fundamental issue for the evaluation of CDM programs is whether the effects observed after the implementation of a distributor CDM activity can be attributed to that activity (otherwise known as causality) or result from the activities of others.

While attribution is not a true adjustment to the TRC test, this issue is important for those distributors that plan on making an LRAM or SSM claim.

Attribution of benefits as between a distributor and a non-rate regulated third party will be determined on a case-by-case basis.[12] In order for the distributor to claim 100% attribution of benefits, the distributor should demonstrate that its role was 'central' to the program. Centrality is established by the distributor if its financial contribution is greater than 50% of program funding or, where the distributor's financial contribution is less than 50% of program funding, the distributor initiated the partnership, initiated the program or initiated the implementation of the program. Where the distributor's financial contribution is less than 50%, the Board expects that the distributor will provide supporting documentation outlining its role in the program.

By extension, should the distributors' role not meet the test of centrality, attribution should be determined between the parties and presented to the Board for approval at a time when it becomes relevant.

Appendix A provides further detail on how the attribution of benefits of a CDM program, and illustrates three cases where attribution may be an issue.

3.4.3 Persistence

Persistence is a measure of how long a CDM measure is kept in place by the customer. Persistence is important for all energy efficiency programs as a lack of persistence can have very significant effects on overall net program savings estimates. For example, if an energy efficient measure with a 15-year lifetime is removed after only two years, most of the savings expected to result from that installation will not materialize.

Distributors should account for the persistence of a CDM measure in accordance with the inputs and assumptions posted on the Board's website.

3.4.4 Distribution and Transmission System Losses

[12] See the March 3, 2006 Decision of the Board in proceeding RP-2005-0020/EB-2005-0532.

It is clear that system[13] losses are a reality for both distributors and the transmission grid. It is also intuitive that CDM initiatives that lower demand or energy use will also lower line losses. By recognizing a program's potential to lower system losses, a program becomes more cost effective than it otherwise would have been, and therefore more worthwhile for a distributor to deliver the program. This is a positive outcome. As such, including system losses in the calculation of the benefits of CDM is appropriate.

In Ontario, distribution infrastructure and load shapes vary significantly from distributor to distributor. This has a direct impact on distribution system losses. Distributors with older systems could have higher system losses than those with newer infrastructure. Distributors that have load shapes where there is a significant difference between the peak and the average load are also likely to have higher system losses. System losses are significantly higher during peak demand periods because they vary by the square of the load.

Distributors should adjust the energy savings used in the benefit-cost analysis of CDM programs to account for distribution and transmission system losses as follows:

- Distribution system losses should be those specific to the distributor, and be the most recent annual loss values reported to the Board.
- Transmission system losses should be valued at 2.5%.

Distribution and transmission system losses should be used only for the benefit-cost analysis, and should not be included in the calculation of LRAM or SSM.

The system losses should also be included in distributors' annual reports on their CDM activities. Finally, the use of the distribution and transmission system losses in the TRC assessment should be done in a manner where both demand and energy are adjusted.

[13] System losses include both technical and non-technical losses. Technical losses are primarily due to heat dissipation resulting from current passing through resistance in conductors and from magnetic losses in transformers. Non-technical losses occur as a result of theft, billing errors, metering inaccuracies and unmetered energy.

4.0 ACCOUNTING TREATMENT

4.1 Cost Allocation

Distributors should use a fully allocated costing methodology for all distributor-delivered CDM activities. Capitalized assets associated with CDM activities that are funded through rates will be included in rate base, and will be treated in the same manner as distribution assets. Assets purchased with funds from the OPA will not be eligible for inclusion in rate base, nor will any ongoing operating costs associated with the asset, or payments in lieu of taxes ("PILs") or income taxes payable in relation to OPA funded activities.

Where the funding is coming from the OPA, the separation in costs will appropriately establish distribution rates by eliminating any cross subsidization between OPA-funded CDM activities, and those activities funded through distribution rates. Where the funding would be from the distributor's rates, fully allocated costing will ensure that there is an appropriate basis to determine the cost effectiveness of CDM programs.

Appendix B sets out guidelines to assist distributors with the implementation of fully allocated costing.

4.2 Revenue Allocation

Consistent with the treatment of costs associated with OPA-funded CDM activities, revenues earned from OPA-funded CDM activities are to be kept separate from (i.e. not used to offset) the distributor's distribution revenue requirement.

Any net revenues generated by a shareholder incentive for distribution rate-funded CDM should also be separate from (i.e. not used to offset) the distributor's distribution revenue requirement.

4.3 Recording of CDM Spending

OPA-funded CDM programs are classified as non-distribution activities. Consequently, OPA-funded CDM revenues, expenses, payments in lieu of taxes ("PILs") or income taxes payable, assets or liabilities are not recognized for rate-setting purposes. The financial records associated with OPA-funded CDM should be separate from those associated with the distributor's distribution activities.

A distributor receiving OPA-funded CDM revenues and incurring related CDM expenses and/or capital expenditures should record these transactions in separate non-distribution accounts in the Uniform System of Accounts. For this purpose, account 4375, Revenues from Non-Utility Operations, should be used for revenues and account 4380, Expenses from Non-Utility Operations, should be used for expenses. Sub-accounts may be used as appropriate.

5.0 LOST REVENUE ADJUSTMENT MECHANISM (LRAM)

Unforecasted CDM results can have the effect of eroding distributor revenues due to lower than forecast throughput. Distributors recover fixed distribution costs through both a fixed and a variable rate, which is set based on a forecast of consumption, including natural changes in energy efficiency. If actual consumption is less than the forecasted amount used for rate-setting purposes, the distributor earns less revenue than it otherwise would have, all other things being equal. Since the intention and effect of CDM activities is to reduce capacity and energy use, it also has the effect of reducing throughput and associated distributor revenues, which can result in a disincentive for distributors to deliver CDM programs.

A mechanism to compensate for distributor-induced lost revenues is intended to remove the disincentive. LRAM is a retrospective adjustment, which is designed to recover revenues lost from distributor supported CDM activities in a prior year. It is designed to compensate a distributor only for unforecasted lost revenues associated with CDM activities undertaken by the distributor within its licensed service area.

5.1 Eligible programs

LRAM is available regardless of whether the programs are funded by the OPA or through distribution rates. The LRAM applies to programs implemented by the distributor, within its licensed service area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party (under contract with the distributor, either in relation to rate-funded programs, or where the distributor has contracted with the OPA but has outsourced CDM program delivery to a third party).

Distributors may undertake some programs in partnership with other entities, such as natural gas utilities or community agencies. In assessing the distributor's involvement in program delivery, and the resulting potential impacts on revenue, distributors should be guided by section 3.4.2, regarding the attribution of benefits. Distributors may only recover LRAM for revenue losses that can be attributed to the distributor's involvement in the program.

5.2 Calculation of LRAM

The LRAM is determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class. The calculation does not include any Regulatory Asset Recovery rate riders, as these funds are subject to their own independent true-up process. Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.

LRAM amounts to be recovered in rates should be adjusted for free riders.[14] As noted above, free riders are those customers who would have adopted or installed an energy efficiency measures regardless of the involvement of the distributor. This is often called natural conservation. Given that the LRAM is intended to compensate distributors for revenue losses resulting from the distributor having implemented a CDM program, the LRAM should be adjusted to remove the free riders.

As indicated by the filing guidelines set out in section 9.2, distributors should include in the application for recovery of LRAM the kW or kWh impacts of each program and for each class both gross and net of free riders. The amount to be recovered through rates will be determined as net of free riders.

5.3 Timing of Application

When applying for LRAM, a distributor should ensure that sufficient time has passed to ensure that the information needed to support the application is available.

Distributors may submit an application for recovery of LRAM amounts at any time following the end of the approved plan term. However, as noted in section 2.1.1, the Board is of the view that such applications are best considered as part of a broader cost-of-service rate proceeding.

[14] See the September 11, 2007 Decision and Order of the Board in proceeding EB-2007-0096.

6.0 SHARED SAVINGS MECHANISM (SSM)

LRAMs remove a disincentive for distributors to implement CDM, but do not provide an incentive for distributors to aggressively implement CDM programs. Given a certain level of resources, the distributor should make a trade-off between pursuing a CDM activity versus other activities.

A shareholder incentive is an appropriate way to encourage distributors to pursue CDM programs.

6.1 Eligible programs

The SSM is available for customer focused initiatives that are funded through distribution rates and where the costs of the initiatives are expensed, such as efficiency improvements in the use of electricity. The SSM is not available for utility-side expenditures or programs that are not funded through distribution rates, such as those funded by the OPA. Where a program is initially funded through distribution rates, but is subsequently funded by the OPA, SSM will only be available for the period in which the program was funded through distribution rates.

Distributors may undertake some programs in partnership with other entities, such as natural gas utilities or community agencies. In assessing the distributor's involvement in program delivery, distributors should be guided by the guidelines set out in section 3.4.2, regarding the attribution of benefits. Distributors may only claim a shareholder incentive in relation to its contribution to the program, as determined by the attribution guidelines.

6.2 Calculation of SSM

The distributor should calculate the net benefits of a program using the TRC test, and adjusting for free riders. Under the SSM regime, a distributor may recover 5% of the net benefits created by the approved CDM portfolio. The SSM is a pre-tax amount.[15] In addition, the SSM should be calculated across the entire portfolio of CDM programs, including any programs with negative benefits.

6.3 Timing of Application

When applying for SSM, a distributor should ensure that sufficient time has passed to ensure that the information needed to support the application is available.

Distributors may submit an application for recovery of SSM amounts at any time following the end of the approved plan term. However, as noted in section 2.1.1, the

[15] See the September 11, 2007 Decision and Order of the Board in proceeding EB-2007-0096.

Board is of the view that such applications are best considered as part of a broader cost-of-service rate proceeding.

7.0 PROGRAM EVALUATION

Effective monitoring, evaluation, verification and reporting of CDM program outcomes is a critical part of ensuring that programs are cost effective, generating the desired outcomes, and providing real savings to consumers. Evaluation also provides distributors with the opportunity to identify ways in which a program can be changed or refined for greater efficiency in delivery and cost effectiveness.

Distributors should undertake evaluations of programs funded through distribution rates. The evaluation of CDM activities is important to support the Board's review and approval of LRAM and SSM claims made by distributors. Evaluation of the energy savings of a program is needed to determine the impact on a distributor's revenues as a result of reduced throughput.

The California Evaluation Framework identifies two key functions of evaluation:

1. To document and measure the effects of a program – "Summative Evaluations".
2. To help understand why those effects occurred and identify ways to improve the program – "Formative Evaluations".

The first function represents a threshold for assuring accountability for the expenditure of resources on that program. Evaluation activities are done after the program has been operating and focus on documenting impacts with a view to informing decisions regarding continuation, expansion or cancellation of the program. Formative evaluations (often referred to as process evaluations) may be done earlier in a program's continuum and focus on providing feedback regarding the operational effectiveness of a program. The results of the evaluation serve to inform decisions regarding mechanisms to improve the program.

A key tenet of good program evaluation practices is the identification of the evaluation activities as part of the initial program design. This ensures that the operational characteristics of the program generate the data and information that can assist in the program evaluation. This can be as simple as collecting relevant contact information as part of the operation of the program which will be used in follow-up activities, or more complicated activities such as pre and post implementation metering of equipment. In both cases, the evaluation techniques and parameters are integrated with the design and operation of the program.

It is incumbent on distributors to attempt to improve their programming capabilities over time. This may involve re-visiting the programs from time to time through the use of process evaluations that examine the effectiveness of the delivery. All programs should consider a certain level of process evaluation effort at some point. Typically, process evaluations occur earlier in a program's life rather than later – i.e. early enough to revise the program as a result of the evaluation. This will vary based upon the size and nature of the programs, where they are in their life, and the similarity (or lack of similarity) to other distributor programs. For small programs, the evaluation effort could focus on

secondary research augmented by interviews with key personnel involved in the program. Larger programs might involve greater depth of evaluation including market research, surveys with participants and non-participants and related primary research activities. In the end, the intent is to ensure that programs operate at the highest level of effectiveness and that the process evaluation results are made available to other distributors to assist them in their delivery.

7.1 Evaluation Plan

An overarching element of effective evaluation is the need to identify, at the outset, how each program will be evaluated. This establishes both the individual metrics that will be measured/tracked and evaluated and the mechanisms that will be used. It further ensures that the evaluation effort is adequately contemplated and resourced.

Distributors should file an Evaluation Plan along with the application for funding for any program(s). Approval of the distributor's CDM plan will be conditional upon approval of an acceptable Evaluation Plan for the program(s) contained in the CDM plan.

The purpose of the Evaluation Plan will be to identify the key evaluation metrics, activities and outcomes associated with each of the distributor's CDM programs.

It is recognized that not all programs will need an evaluation effort in each year. However, at a minimum the distributor should anticipate and plan for a certain level of evaluation activities over the continuum of a program's life.

In addition to meeting the evaluation objectives listed below, any Evaluation Plan should include the distributor's proposed methodology for:

- Measuring program effects (summative evaluation); and,
- Assessing why effects occurred, and how the program can be improved (formative or process evaluation)

The Evaluation Plan(s) should outline how the distributor will accomplish the following evaluation objectives:

- Measuring the level of energy and peak demand savings achieved;
- Measuring cost-effectiveness;
- Informing decisions regarding LRAM and SSM amounts;
- Providing ongoing feedback, and corrective and constructive guidance regarding the implementation of programs; and,

Helping to assess whether there is a continuing need for the program.

7.2 Program Type Specific Guidelines

This section focuses on the guidelines, in addition to those set out above, for tracking and measuring the effects of the following three types of CDM programs:

1. **Direct acquisition** programs are programs that have clear causality between distributor activity and energy savings.
2. **Market support/outreach** programs are programs in which the distributor supports outreach or educational efforts which generally promote the energy efficiency message, but where savings are indirect and it is difficult to see a clear cause and effect relationship.
3. **Custom projects** are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment and technology that is not identified in the list of inputs and assumptions posted on the Board's website.

7.2.1 Direct Acquisition Programs

Direct acquisition programs are relatively straightforward to track and measure. Tracking represents one of the administrative functions of program delivery. While the specifics will vary for each type of program, there is a need to show clear cause and effect between the distributor's activities and the customer's load reduction. In direct acquisition programs, this is often precipitated by the processing of a participant incentive. Distributors will need to have systems for collecting relevant information for each program, including:

- technology type;
- number of installations;
- savings estimates;
- equipment cost estimates;
- customer address or location;
- delivery channel; and,
- incentive amount.

It may not be feasible to collect all information for all programs. For example, a program delivered by a retailer that relies on in-store coupons will likely not have the means to track who actually used the coupons and received the product(s). However, the retailer can be expected to track information about the number of coupons turned in, and the distributor's tracking system could then calculate the resulting cost to the distributor. With this information, the distributor can then calculate the savings and equipment cost and combine the information with equipment life, free rider estimates and program costs - resulting in both a tracking report and the components of the TRC analysis.

In the case of a program delivered by a third party, tracking will include reports that the delivery partner provides to the distributor. These reports should provide details on the customer visits, including address and equipment installed.

7.2.2 Market Support Programs

Load reductions from CDM activities related to training, public outreach and the general provision of information on efficient energy use are difficult to track, measure and establish clear causality. Since market support programs typically do not result in direct demand or energy savings, other assessment criteria should be used to assess their benefits. Each market support activity should attempt to have at least one metric.

Below is a sample of potential tracking activities that might accompany the delivery of market support programs. Each market support activity should attempt to have at least one metric.

Support	Metric	Additional Information
Web-site calculator	Number of hits	Survey re: usefulness of website
Training sessions for contractors	Number of sessions Number of attendees	Survey re: specific activities undertaken by attendees
Home shows	Number of giveaways	Survey re: energy efficient appliances
Design workshops	Number of professional attendees	Surveys re: design activities

7.2.3 Custom Projects

Custom projects are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment or technology not identified in the list of inputs and assumptions posted on the Board's website. Projects that involve a combination of several measures provided in the list of inputs and assumptions posted on the Board's website are not considered to be custom projects.

For a custom project, distributors will need to track:

- the type of equipment that was installed;
- the related savings and equipment cost; and,
- distributor support costs.

Since custom projects usually involve specialized equipment, savings estimates should be assessed accordingly. It is expected that each custom project will incorporate a professional engineering assessment of the savings. This assessment would serve as the primary documentation for a claim that savings exist.

A special assessment program should be implemented for custom projects. The assessment should be conducted on a random sample consisting of 10% of the large custom projects; and the projects should represent at least 10% of the total volume savings of all custom projects. The minimum number of projects to assess would be 5. Where less than 5 custom projects have been undertaken, all projects should be

assessed. The assessment will focus on verifying the equipment installation and estimates of savings and equipment cost.

7.3 Implementation of Updated Input Assumptions

The input assumptions used to screen CDM technologies and programs may change over time due to more accurate and up-to-date information. This can impose a risk on distributors that the actual program impacts, LRAM or SSM are not those expected based on a given set of assumptions. The timing at which changes in assumptions become effective will differ depending on the use of the assumption, as follows:

Program Design and Implementation
Distributors should design, screen and evaluate programs using the best available information known to them at the relevant time. Therefore, it is expected that distributors will incorporate new information into program design and implementation as soon as feasible, subject to relevant operational considerations. In considering the prudence of any spending in excess of an approved budget that has been tracked in a CDM variance account, the Board will consider the information available to the distributor at the time the program was implemented. That is, when amounts in a CDM variance account are being reviewed for the purposes of disposition, the Board will consider the information available to the distributor at the time the spending decision was made by the distributor. This will apply even if the input assumptions have changed since that time.

LRAM
The input assumptions used for the calculation of LRAM should be the best available at the time of the third party assessment referred to in section 7.5.

For example, if any input assumptions change in 2007, those changes should apply for LRAM purposes from the beginning of 2007 onwards until changed again.

Assume a program was delivered from January 1, 2007 until December 31, 2007. In June 2007, it was determined that the free rider rate used in the initial program analysis was under-stated. The distributor obtains a third party review of its evaluation of program results in April 2008. The input assumptions that will apply in relation to any lost revenue between January 1, 2007 and December 31, 2007, will be those that were introduced in June 2007. That is, the new free rider rates apply for the entire period from January 1, 2007 to December 31, 2007.

SSM
Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year. For example, if any input assumptions change in 2007, those changes should apply for SSM purposes from the beginning of 2008 onwards until changed again.

Assume a program was delivered from January 1, 2007 until December 31, 2007. In June 2007, it was determined that the free rider rate used in the initial program analysis was under-stated. The distributor obtains a third party review of its evaluation of program results in April 2008. The input assumptions that will apply in relation to SSM amounts for a program delivered from January 1, 2007 and December 31, 2007, that the third party reviewer should confirm, will be those that were in effect on December 31, 2006. The new free rider rates would only apply for SSM purposes to programs that began January 1, 2008.

7.4 Evaluation Report

A distributor that makes an LRAM or SSM claim, whether in relation to programs funded by the OPA or through distribution rates, will need to file a detailed Evaluation Report at the time of making that claim. The Evaluation Report should consist of the following sections:

(1) Introduction

In the "Introduction" section of the Evaluation Report, distributors should provide a general overview of their CDM initiatives including any relevant local context.

(2) Evaluation of the CDM Plan

This section will provide an overview of the effectiveness of a distributor's CDM Plan. Distributors should report on all initiatives worked on and detail the process and impact analysis of the individual programs.

Note:
Stand alone education or marketing programs that do not have quantifiable benefits should report all relevant information (some relevant assessment criteria are identified in section 7.2.2). Marketing or support programs (i.e., programs designed to enhance market acceptance of other programs) should not be reported individually as they are components of other programs. Similarly, the costs of marketing or support programs should be allocated to the programs they support.

Distributors who have pilot programs (see section 2.1.3), or other programs for which cost effectiveness data was not provided by the Board (on the Board's website) should provide their own values, if available, and report all relevant information (attach a separate table if needed).

If the inputs and assumptions used by the distributor vary from those posted on the Board's website, the variation(s) should be identified, and additional information supporting the variation(s) should be filed. [16] If the specific

[16] The Board would consider a distributor to have varied from assumptions posted on the Board's website if the distributor used an input assumption that is not included on the Board's list, or used an input

technology promoted by a distributor was not included by the Board (on the Board's website), the distributor may select a similar technology as a proxy for annual reporting purposes. A distributor that selects a proxy technology for reporting should identify the actual technology in its Evaluation Report and the similarities between the proxy technology and the actual technology. However, for the purposes of a claim for recovery of LRAM or SSM, where a distributor uses a proxy technology, the distributor should provide detailed evidence justifying the appropriateness of using the proxy technology, and detail the steps the distributor has taken, or will take, to determine the actual data for the technology used in the CDM program.

(3) Lessons Learned

In the "Lessons Learned" section the distributor will indicate what has been learned over the course of the program. The goal of this section is to evaluate and benchmark programs for greater efficiency in delivery and cost effectiveness, and to provide information to other distributors with respect to CDM programs. Distributors should indicate if a program is considered a success or not and whether the distributor should continue its delivery.

(4) Conclusion

The "Conclusion" section will consist of the distributor's summary of its performance relative to the CDM Plan approved by the Board.

7.5 Independent Third Party Review

Given the ratemaking implications of program evaluations, intervenors, ratepayers and the Board need to be confident that evaluations are an accurate reflection of actual program results. Where a distributor is making a claim for LRAM in relation to programs funded by the OPA, or where the distributor is making a claim for LRAM and/or SSM in relation to programs funded through distribution rates, distributors should engage an independent third party. This independent third party review applies to LRAM or SSM claims made in relation to programs funded in 2007 and beyond.

OPA Funded CDM Programs

As part of a claim for LRAM in relation to programs funded by the OPA, distributors should submit to the Board an independent third party evaluation of program results. The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient.

For programs funded by the OPA, it will be the role of the third party to:

- Verify the participation levels; and,
- Confirm that input assumptions are those used by the OPA.

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assumption from the Board's list as a proxy value, because the list does not include an assumption for the program or the technology used.

CDM Programs Funded Through Distribution Rates

In relation to programs funded through distribution rates, distributors should undertake program evaluations, and have the evaluations reviewed by an independent third party for the purposes of LRAM and SSM claims filed with the Board.

The third party, although hired by the distributor, should be independent and should ultimately serve to protect the interests of ratepayers. Distributors should ensure that CDM budgets and spending include adequate funding to procure the third party review.

For programs funded through distribution rates, it will be the role of the third party to:

- Provide an opinion on the cost effectiveness results that are material to the LRAM and SSM amounts proposed;
- Verify the participation levels;
- Confirm that the input assumptions are those posted on the Board's website. Where any input assumptions have changed in previous years, confirm that the input assumptions were implemented consistent with section 7.3;
- Where the distributor has varied from the input assumptions posted on the Board's website, review the reasonableness of the input assumptions used;
- Recommend any forward looking evaluation work to be considered; and,
- Recommend any improvements to the program to enhance program design, performance, and uptake by customers.

8.0 ANNUAL REPORTING GUIDELINES

The guidelines set out in this section relate only to CDM programs funded through distribution rates.

Reporting on the progress and success of CDM programs is critical to maintaining accountability and transparency. For programs funded through distribution rates, distributors should file annual reports, by April 30 of each year. Where distributors have approved funding for more than one year, a report should be filed annually summarizing the results of the previous year, and at the end of the plan term, addressing results for the entire plan term.

Given that distributors may have approved CDM plans that span more than one year, annual reporting will be an important tool to allow the Board and stakeholders to monitor distributors' year-over-year progress in the implementation of their CDM plans. The annual report should provide the Board and stakeholders with information on what CDM activities the distributor is undertaking, how it is performing, what it is costing, and the distributors' planned future activities.

Where distributors have separate streams of funding, for example, third tranche and 2007 funding, results should be differentiated in the Annual Report.

The Annual Report should consist of the following sections:

1. **Introduction**
   In the "Introduction" section of the annual report, distributors should provide a general overview of their CDM initiatives including any relevant local context.

2. **Description of the program**
   In this section, the distributor should provide an overview of the program, including the targeted customer class or group, the objectives of the program, and any activities associated with the program.

3. **Participation levels**
   In this section, distributors should detail the number of participants for each program.

4. **Energy savings in kW and kWh**
   In this section, distributors should provide the annual and cumulative energy savings attributable to each program, presented as both net and gross of free riders.

5. **Comments**
   In this section, distributors should provide any additional information as appropriate. This may include the distributor's assessment of the success of

the programs to date, what activities are planned for the subsequent year(s) and any planned modifications to program design or delivery.

ADMINISTRATION

9.0 FILING GUIDELINES

This section contains the Board's filing guidelines for the following types of applications:

9.1 Program funding through distribution rates
9.2 Lost Revenue Adjustment Mechanism
9.3 Shared Savings Mechanism
9.4 Adjustments to an approved CDM plan

The Board expects that distributors will comply with these filing guidelines as a minimum. Distributors are reminded that they should in all cases demonstrate to the satisfaction of the Board that any given application should be approved, and are responsible for ensuring to that end that all relevant information is before the Board (including evidence that may have been filed in an earlier proceeding). In addition, the Board may make any order or given any direction as the Board determines necessary concerning any matter raised in relation to any of the above applications, including in relation to the production of additional information which the Board on its own motion or at the request of a party considers appropriate.

9.1 Program Funding through Distribution Rates

An application for funding through distribution rates for new programs should include:

1. **Characteristics of the applicant's distribution system, including:**
   - Peak system load by season;
   - Average seasonal daily and weekly system load shapes;
   - Total energy purchases;
   - Sales by rate class; and
   - Number of customers by rate class.

2. **For each initiative, the following information should be provided:**
   - Detailed description of the programs;
   - Customer class(es) targeted;
   - Projected incremental demand (kW) or energy (kWh) savings per year;
   - Projected budget, listing:
     - capital expenditures per year, for each year of the plan;
     - operating expenditures per year, for each year of the plan, separated into direct and indirect expenditures;
     - for each direct operating expenditure, an allocation of the expenditure by targeted customer classes; and
     - expenditures for evaluation of the program(s).
   - Measure, programs and portfolio cost effectiveness results;

- The input assumptions underlying the forecasted savings and costs including a detailed presentation of the calculations;
- Where a program involves the implementation of specialized equipment or technology not identified in the list of inputs and assumptions posted on the Board's website, the distributor should comply with the guidelines set out in section 7.2.3 respecting custom projects;
- A statement as to whether the distributor has varied from the list of inputs and assumptions posted on the Board's website. Where the distributor has varied from the list of inputs and assumptions posted on the Board's website, the distributor should provide, in accordance with section 3.2.2, detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C to the Guidelines;
- The benefit-cost analysis, calculating the net present value of the initiative using the TRC test. For the purpose of calculating the net present value, a distributor should use a discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity; and,
- A discussion of whether the proposed initiative is similar to any currently funded by the OPA.

3. The distributor should also provide the following, set out on a per year basis, for each year of the plan:

- The total amount of CDM spending to be recovered in rates and the allocation of those costs to the customer class(es) that will benefit from the conservation program applied for;
- A forecast of the number of customers in each class and a forecast of kWs or kWhs to be used as a charge determinant to determine the rate rider for each class to benefit from the CDM program; and
- A comparison of the proposed rates with and without the CDM rider for the rate year in question.

4. An Evaluation Plan, in accordance with section 7.1.

5. In addition to the information above, the following information should be provided for pilot programs (see section 2.1.3):

- A description of the technology being used;
- A discussion of whether and how, to the distributor's knowledge, the technology is being used or tested by any other distributors. Where the technology is being used by another distributor, a description of how the distributor will coordinate or work with the other distributor using or testing the technology to ensure effective use of the program and of lessons learned; and

- The expected outcome of the pilot program. That is, what data or information will the program produce, and how will it be used for future CDM programs.

9.2 Lost Revenue Adjustment Mechanism (LRAM)

Section 5.0 contains information on the programs that are eligible for LRAM, the calculation of LRAM, and the timing of any application for recovery of LRAM.

An application for LRAM should include:

OPA Funded Programs

- kW or kWh impacts (both gross and net of free riders) of *each program* and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Duration of the program in years or months;
- An Evaluation Report, in accordance with the guidelines set out in section 7.4; and,
- Any reports completed by an independent third party, in accordance with the guidelines set out in section 7.5

Programs Funded through Distribution Rates

For programs funded through third tranche, and 2006 incremental funding:

- kW or kWh impacts (both gross and net of free riders) of *each program* and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the list of inputs and assumptions posted on the Board's website, the distributor should comply with the guidelines set out in section 7.2.3 respecting custom projects;
- A statement as to whether the distributor has varied from the list of inputs and assumptions posted on the Board's website. Where the distributor has varied from the list of inputs and assumptions posted on the Board's website, the distributor should provide, in accordance with section 3.2.2,

detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C to the Guidelines; and,
- Duration of the program in years or months.

For programs funded in 2007 and beyond, the following information is should be provided, in addition to the guidelines set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 7.4; and,
- All reports completed by an independent third party, in accordance with the guidelines set out in section 7.5.

All information filed for the LRAM proposal should correspond to program information used in the calculation of the benefit-cost analysis.

9.3 Shared Savings Mechanism (SSM)

Section 6.0 contains information on the programs that are eligible for SSM, the calculation of SSM, and the timing of any application for recovery of SSM.

An application for SSM should include:

For programs funded through third tranche, and 2006 incremental funding:

- kW or kWh impacts (both gross and net of free riders) of each program and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the list of inputs and assumptions posted on the Board's website, the distributor should comply with the guidelines set out in section 7.2.3 respecting custom projects;
- A statement as to whether the distributor has varied from the list of inputs and assumptions posted on the Board's website. Where the distributor has varied from the list of inputs and assumptions posted on the Board's website, the distributor should provide, in accordance with section 3.2.2, detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template", attached as Appendix C to the Guidelines; and,
- Duration of the program in years or months.

For programs funded in 2007 and beyond, the following information should be provided in addition to the information set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 7.4; and,
- All reports completed by an independent third party, in accordance with the guidelines set out in section 7.5.

9.4 Adjustments to an Approved Plan

The Board encourages distributors to evaluate the effectiveness of programs on an ongoing basis, and to make adjustments as necessary to improve program design, performance, and uptake by customers. Where cumulative fund transfers among programs are less than 20% of the approved annual budget, no Board approval is necessary.

Distributors should apply for Board approval for cumulative fund transfers among programs that exceed 20% of the approved annual budget.

An application for adjustments to an approved plan should include:

- Current and proposed budgets for programs affected by the re-allocation;
- A description of the programs from which, and to which, funds are being re-allocated;
- Whether the distributor is requesting that the Board to proceed in accordance with section 21(4)(b) of the *Ontario Energy Board Act, 1998*, under which the Board can dispose of the proceeding without a hearing;
- Where funding is being allocated to a program or programs that are not part of the distributor's approved CDM plan, the distributor should also follow the guidelines set out in section 9.1 in relation to the new program(s). That is, in addition to applying for approval for the proposed budget re-allocation, the distributor should also apply for approval of the proposed new program(s).

APPENDIX A:

Guidelines for Applying the Total Resource Cost Test

Appendix A – Guidelines for Applying the Total Resource Cost Test

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Overview

These Guidelines for Applying the Total Resource Cost Test (the "TRC Guidelines") are a companion document to the Board's Guidelines for Electricity Distributor Conservation and Demand Management (the "Guidelines") and provides additional information to assist electricity distributors in preparing benefit-cost analyses of CDM programs. It is an explanatory document for undertaking TRC cost effectiveness analysis, and includes the mathematical formulae and sample TRC calculations.

The examples set out in this document are for illustrative purposes only, and do not necessarily represent actual costs, energy consumption or energy savings.

1.0 The Total Resource Cost Model

As set out in the Guidelines, CDM initiatives should be evaluated on the basis of a cost effectiveness test known as the Total Resource Cost (TRC) test**.** The TRC test is defined as a test that *"measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the [distributor's] costs".*[1]

1.1 Formula for Performing TRC Test

The TRC test examines streams of benefits and costs and uses discounting principles to express these future values as a single number. The benefits stem from the avoided resource costs, typically electricity. The costs are the cost of the equipment and the distributor program costs. Subtracting the costs from the benefits provides the net benefits. For a program to be considered cost effective, the net benefits must be greater than zero.

The NPV_{TRC} formula is as follows:

Figure 1.1: Net Present Value$_{TRC}$ Formula

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

where;

$$B_{TRC} = \sum_{t=1}^{N} \frac{AC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t}{(1+d)^{t-1}}$$

and,

B_{trc}	=	the benefits of the program
C_{trc}	=	the costs of the program. Where a measure includes fuel switching for a given end use, the cost of the other fuel must be included in the cost component of the TRC formula.
AC_t	=	avoided costs in year t
UC_t	=	distributor program costs in year t
PC_t	=	Participant cost in year t
N	=	Number of years for the analysis (i.e. the equipment life of the CDM technology)
d	=	discount rate. For the purposes of calculating the net present value,

[1]California Public Utilities Commission. (2001) Standard Practice Manual: Economic Analysis of Demand-Side Management Programs and Projects.

distributors must use a discount rate equal to the incremental after-tax cost of capital, based on the latest prospective capital mix, debt and preference share cost rates, and approved rate of return on common equity. This is consistent with the manner in which net present value calculations are done for purposes of the Distribution System Code.

1.2 Electrical Energy and Demand Savings

Section 3.2.2 of the Guidelines discusses the role of energy and demand savings in the TRC test. The frame of reference assumed can dramatically alter the energy savings estimates. The example set out below assumes that a distributor may wish to offer a program targeting *replacement* of old primary refrigerators with Energy Star™ refrigerators, or may offer a program that targets the complete *removal* of old secondary refrigerators.

Example of Replacement and Removal Programs

	Decision / Program	Existing Equipment	Base Case	Equipment	Savings	Measure Lives
A	Replace old primary refrigerator with a new one	1960's vintage refrigerator using 1,500 kWh/yr	Standard refrigerator using 514 kWh/year	New Energy Star refrigerator using 440 kWh/yr	Base Case – Energy Star 514 – 440 = 74 kWh/yr	19 years
B	Retire and remove old secondary refrigerator	1960's vintage refrigerator using 1200 kWh/yr	Keep using existing refrigerator		1200 kWh/yr	6 years

In this example, depending if the old refrigerator is the primary or secondary refrigerator in the home, and whether it is replaced or completely removed (i.e. different base cases), there is a significant difference in the savings estimates.

A) Replace old primary refrigerator with a new one:
In the case of the replacement, the distributor must estimate the energy use for both the "base case" equipment (i.e. the standard refrigerator) and the Energy Star™ higher efficiency refrigerator. In this case, the base case refrigerator uses 514 kWh/yr while the energy efficient refrigerator uses 440 kWh/yr. Since the program targets the installation of an Energy Star™ refrigerator over the base case option, the difference of 74 kWh/yr is the appropriate savings estimate for the program.

B) Retire and remove old secondary refrigerator:
For the removal program there is no replacement with either a base case or energy efficient model. Since the program encourages the removal of the old refrigerator, the appropriate savings estimate is 1200 kWh/year.

Load impacts must be defined in a manner consistent with other assumptions in the CDM program assessments. Impacts must be calculated over the same time horizon used in the program design and for the same costing periods used in defining the

marginal costs. Impacts must also be consistent with the base case option used to measure incremental costs (see 1.3.1 - Equipment Costs).

1.3 Equipment Costs

Section 3.3.1 of the Guidelines discusses equipment costs, and how these are used in a TRC analysis. The example below uses the same refrigerator example as above to show how the costs will vary depending upon the base case assumption.

Understanding Incremental Costs for TRC Analysis

	Decision / Program	Baseline Equipment	Equipment Cost	Cost
A	Replace old primary refrigerator	1960's vintage refrigerator using 1200 kWh/yr	Base Case refrigerator: $1,000 Energy Star refrigerator: $1,070	"Energy Star" + Removal Fee – Base Case fridge $1,070 + 100 – $1,000 = $170
B	Retire and remove old secondary refrigerator	1960's vintage refrigerator using 1200 kWh/yr	$0	Removal fee estimated to be $100

A) Replace old primary refrigerator
The replacement scenario requires knowledge about both the cost of the base case equipment, the energy efficient equipment and the cost of removal and disposal. The cost to be used in the TRC analysis is the difference between these.

B) Retire and remove old secondary refrigerator
For the refrigerator removal scenario the only costs of the program are those for removal and disposal.

1.4 CDM Program Costs

Section 3.3.2 of the Guidelines discusses how promotion costs are used in a TRC analysis. Below are some sample methods of promotion.

Methods of Promotion

Type of Contact	Tactics
Personal contact with distributor representative	Telemarketing Customer service campaign Door-to-door campaign
Other direct distributor contact	Bill stuffers Direct Mail
Mass media	Print/flyers Television/Radio
Trade allies	Equipment vendors Equipment installers

Note on Distributor Costs for Incentives

While incentives primarily serve to improve the economic attractiveness of CDM investments for the customer, they also serve to increase customer awareness of the programs. As well, an incentive creates a specific paper trail that distributors can use as part of their tracking and evaluation activities.

Distributors may design incentive schemes specific to their customers. Often, payback criteria or rebates are used in incentive design. This approach is often more important to commercial and industrial customers. For these customers, many distributors favour an approach that lowers the payback to a specific threshold, or ensures that incentives are only applied to projects with paybacks above a certain threshold.

An alternative approach is to gauge rebate levels relative to the incremental capital cost of the CDM technology compared to a standard technology that would have been installed in the absence of the program. Rebates are often set at some percentage of incremental cost. In practice, those percentages vary from a fraction of the incremental cost to completely off-setting the incremental costs.

As discussed in section 3.3.2 of the Guidelines incentive payments from the distributor to a customer for participation in a program are not a component of the TRC analysis, but still should be included in the distributor's program budget. The following formula illustrates why the incentive amount is not included in the TRC analysis:

The costs of a program are distributor program costs (UC_t) plus participant cost (PC_t), while the benefits are the avoided costs (AC_t.). If the formula were to include the incentive amounts (INC_t), it could be re-written as:

Costs = $UC_t + PC_t + INC_t$
Benefits = $AC_t + INC_t$

Since the INC_t term is the amount paid by the distributor for the benefit of some third party, it is both a cost and a benefit in the equation. Therefore, for simplicity it can be eliminated from the analysis.

The exclusion of incentives is only for the purposes of calculating the TRC value of a program and they are not excluded in developing the distributors CDM budget. It is important to recognize that the only difference between the utility costs that get recorded in a distributor's TRC analysis and its complete CDM budget is the amount of incentives.

Many CDM programs involve some form of transfer payment (i.e. incentive) between distributors and participants. They are generally characterized as follows:

- rebates;
- loans and leases;
- shared savings arrangements; or,

- participation fees.

1.5 Categorizing Costs

As a matter of practice and for ease of performing cost effectiveness testing, many distributors categorize costs as either direct or indirect.

Direct costs are those that can be clearly allocated to a particular program and may include marketing, consulting and field staff costs among others. Direct costs factor into the program level cost effectiveness analysis. Indirect costs are those costs that can not easily be allocated to any particular program. These costs include overhead, administration and monitoring and evaluation. Indirect costs are typically incurred at the portfolio level and included in the portfolio cost effectiveness analysis.

2.0 Adjustment Factors in the TRC Test

As discussed in section 3.4 of the Guidelines, in performing a TRC analysis, several adjustments must be made to the benefits side of the equation, including:

- free ridership of participants;
- attribution of the benefits;
- persistence of the measures; and,
- distribution and transmission losses.

This section provides additional information on attribution.

2.1 Attribution

Section 3.4.2 of the Guidelines discusses the attribution of benefits between CDM activities funded through distribution rates and activities undertaken by other delivery agents and for savings associated with other resources.

The following discussion addresses the issue of attribution of benefits of a CDM program with respect to the potential claim for a Shared Savings Mechanism ("SSM"). In the case that an SSM is recovered, it must be paid by those ratepayers who are receiving the benefits of the program, therefore, guidelines have been established to attribute the benefits of a program along geographic and industry boundaries.

2.1.1 Attribution Guidelines for CDM Programs

The formula for determining savings associated with a CDM program is:

Savings = (UATES) x (NUD) x (1-FRR)

where;

Savings – kWh/yr and/or other resource measure;

UATES – Unit Annual Total Energy Savings

NUD – Number of Units Delivered

FRR – Free Ridership Rate

In order to estimate the savings attributable to the distributor program an attribution rate is added to the previous formula to get:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR)

where;

AR – Attribution Rate

In most cases, the attribution rate will be 1.0, indicating that the distributor should claim in its TRC calculation all of the benefits associated with the CDM program.

The following discussion illustrates three cases where attribution may be an issue.

Case 1- Programs delivered jointly by distributors with single energy savings (i.e. electricity):

In this case, several distributors work together to market and deliver a CDM program. Each participating distributor is allowed to claim the benefits associated with the program (electricity and water) in their service area. The determining factors are the location of the participants and the benefits associated with the program. Therefore, in this case, the Attributable Savings would be:

Attributable Savings = (UATES) x (NUD_{SA}) x (1-FRR) x (AR)

NUD_{SA} - number of units delivered in a distributor's service area.

AR = 1

Case 2 – Multi energy savings in cross sector (gas and electricity) jointly delivered CDM programs:

In this case, a gas and electric distributor jointly market and deliver a CDM program. Each participating distributor is allowed to claim all of the benefits associated with the energy type they distribute (i.e. gas distributors would claim the gas savings and electricity distributors would claim the electricity demand and energy savings) in their service area. Other benefits, such as water savings, need to be allocated between the gas and electric distributor partners proportionally based on the dollar value of gas and electric TRC savings (i.e. where electricity savings represent 60% of the TRC savings of a program, the electric distributor will claim 60% of the water savings).

Case 3 - Multi energy savings in individually delivered CDM programs:

In this case, a distributor works independently to market and deliver a CDM program. The distributor's program may have energy savings additional to the primary energy savings targeted by the program. Common examples of these are Low Flow Shower Head and Programmable Thermostat programs. In these cases, the benefits of the programs will be electricity and other resource savings (i.e. gas and water). As in Case 1, the savings formula would be:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR)

Where UATES incorporate the savings of other energy sources.

3.0 How To Calculate TRC

This section provides details of how to perform a TRC analysis with examples for a single technology calculation, a program calculation and a portfolio calculation.

A distributor's CDM portfolio is the highest level envelope incorporating all of the costs not captured at the technology and program level. Therefore, a CDM portfolio consists of set of cost effective CDM programs. Similarly, a CDM program is designed around a given cost effective measure or technology. For a measure to be considered cost effective, it must have TRC Net Benefits greater than $0.[2] For a measure to be considered cost effective, it must have TRC Net Benefits greater than $0.

Cost effectiveness screening is assessed at each level of a distributor's CDM initiative.

The TRC calculation relies on estimates of:

- avoided cost;
- demand and energy savings;
- equipment cost;
- distributor program costs;
- equipment life;
- free ridership.

These estimates are used in a standard net present value ("NPV") calculation that relies on a discount rate to express a value for future streams of money and to determine a cost effectiveness result in current dollars.

3.1 Technology Screening Analysis

In its simplest form, the single technology screening analysis calculates the cost effectiveness of a single piece of equipment or technology based purely on its energy efficiency characteristics, its cost and equipment life. This screening analysis is the initial step in considering technologies for inclusion in a CDM program.

To perform the technology screening analysis, the required elements are:

- estimate of per unit savings (kW and kWh) by period;
- estimate of equipment cost; and
- expected equipment life.

This is a simple benefit-cost analysis of the technology on a single unit basis.

Calculating the benefits: The benefits are expressed as the product of the per unit savings (in kW and/or kWh) and the avoided costs. This calculation is done for every year of the life of the equipment. These values are then discounted and summed to express the benefits as a single $NPV_{benefits}$.

[2] Distributors may undertake programming on non-cost effective technologies in the form of pilot programs. The Board's guidelines for pilot programs are set out in section 2.1.3 of the Guidelines.

Calculating the costs: The equipment cost is the cost of the technology, expressed as either its full or incremental cost. In most cases, the cost of the technology is incurred at the beginning of the initiative and no further costs are incurred over the life of the equipment (i.e. a CFL bulb). However, where the energy efficient equipment has ongoing maintenance costs incremental to the base case alternative, these costs should be included in the analysis and discounted appropriately. Once this calculation is performed, it is expressed as a single NPV_{costs}.

Detailed examples are set out below.

Technology Example 1: *A 15 Watt Compact Fluorescent Bulb Replacing a 60 Watt Incandescent Bulb*

Step One – Calculating TRC Benefits

TRC benefits represent a discounted stream of electricity avoided costs, other fuel avoided costs (where other fuel savings exist), avoided participant costs and tax benefits. In practice, avoided participant costs and tax benefits are rarely used. The duration of this stream of avoided costs is determined by the life of the technology. In the case of a 15 W compact fluorescent bulb, the measure life is assumed to be 4 years; therefore the benefits accrue over the 4 year period and are discounted to current net present value (using the prescribed discount rate).

The prescribed savings for a 15 watt compact fluorescent bulb, the assumed electricity energy and demand savings and other technology inputs are shown in the tables below:

Table 4.1 Unit Electricity Energy and Demand Savings

	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
Technology	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
15 W CFL	15.5	7.7	20.3	0.0	11.7	14.0	17.5	17.7	0.000

Table 4.2 Other Technology Inputs Required for Calculating TRC Benefits[3]

	TRC INPUTS						
	Technology Information		Other Fuel Savings/Increases				
Technology	Measure Life	Customer Unit Incremental Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
15 W CFL	4	$2.00	0.00	0.00	0.00	0.00	0.00

[3] Note that free ridership is taken into account at the TRC program evaluation level.

The value of the electricity avoided cost savings are calculated by multiplying unit energy and demand savings in Table 4.1 by the appropriate set of avoided supply costs savings shown in Tables 4.3 and 4.4.

Table 4.3 Electricity Avoided Energy Savings

Year	Ontario Seasonal Average Avoided Costs $/kWh								
	Winter			Summer			Shoulder		
	On Peak	Mid Peak	Off Peak	On Peak	Mid Peak	Off Peak	Mid Peak	Off Peak	
2007	$ 0.1246	$ 0.0843	$ 0.0452	$ 0.1115	$ 0.0796	$ 0.0459	$ 0.0814	$ 0.0408	
2008	$ 0.1154	$ 0.0868	$ 0.0489	$ 0.1106	$ 0.0836	$ 0.0501	$ 0.0904	$ 0.0449	
2009	$ 0.1119	$ 0.0771	$ 0.0489	$ 0.1045	$ 0.0795	$ 0.0476	$ 0.0858	$ 0.0434	
2010	$ 0.1135	$ 0.0774	$ 0.0521	$ 0.1070	$ 0.0805	$ 0.0482	$ 0.0835	$ 0.0434	
2011	$ 0.1102	$ 0.0773	$ 0.0527	$ 0.1032	$ 0.0813	$ 0.0485	$ 0.0842	$ 0.0430	
2012	$ 0.1124	$ 0.0789	$ 0.0533	$ 0.1131	$ 0.0846	$ 0.0512	$ 0.0885	$ 0.0478	
2013	$ 0.1252	$ 0.0864	$ 0.0599	$ 0.1169	$ 0.0913	$ 0.0540	$ 0.0925	$ 0.0519	
2014	$ 0.1257	$ 0.0924	$ 0.0628	$ 0.1279	$ 0.0968	$ 0.0567	$ 0.0989	$ 0.0544	
2015	$ 0.1274	$ 0.0947	$ 0.0696	$ 0.1516	$ 0.1067	$ 0.0625	$ 0.1028	$ 0.0599	
2016	$ 0.1317	$ 0.0973	$ 0.0709	$ 0.1525	$ 0.1081	$ 0.0639	$ 0.1045	$ 0.0614	
2017	$ 0.1360	$ 0.1000	$ 0.0721	$ 0.1535	$ 0.1095	$ 0.0653	$ 0.1062	$ 0.0628	
2018	$ 0.1403	$ 0.1027	$ 0.0734	$ 0.1544	$ 0.1109	$ 0.0668	$ 0.1080	$ 0.0643	
2019	$ 0.1446	$ 0.1054	$ 0.0746	$ 0.1553	$ 0.1123	$ 0.0682	$ 0.1097	$ 0.0657	
2020	$ 0.1489	$ 0.1081	$ 0.0759	$ 0.1563	$ 0.1136	$ 0.0696	$ 0.1114	$ 0.0672	
2021	$ 0.1524	$ 0.1104	$ 0.0780	$ 0.1571	$ 0.1165	$ 0.0715	$ 0.1147	$ 0.0691	
2022	$ 0.1558	$ 0.1127	$ 0.0800	$ 0.1579	$ 0.1194	$ 0.0734	$ 0.1179	$ 0.0710	
2023	$ 0.1593	$ 0.1150	$ 0.0821	$ 0.1587	$ 0.1224	$ 0.0753	$ 0.1211	$ 0.0729	
2024	$ 0.1627	$ 0.1173	$ 0.0842	$ 0.1595	$ 0.1253	$ 0.0772	$ 0.1243	$ 0.0748	
2025	$ 0.1661	$ 0.1197	$ 0.0863	$ 0.1603	$ 0.1282	$ 0.0791	$ 0.1275	$ 0.0767	

Table 4.4 Electricity Avoided Demand Savings

Year	Ontario Seasonal Average Avoided Costs $/kW	
	Generation Capacity	Transmission Capacity
2007	$ -	$ -
2008	$ 74.65	$ 5.62
2009	$ 83.57	$ 5.76
2010	$ 71.49	$ 5.90
2011	$ 85.42	$ 6.05
2012	$ 81.20	$ 6.20
2013	$ 61.60	$ 6.36
2014	$ 46.63	$ 6.52
2015	$ 23.16	$ 6.68
2016	$ 26.88	$ 6.85
2017	$ 29.94	$ 7.02
2018	$ 31.66	$ 7.19
2019	$ 32.41	$ 7.37
2020	$ 31.85	$ 7.56
2021	$ 38.27	$ 7.74
2022	$ 41.97	$ 7.94
2023	$ 44.22	$ 8.14
2024	$ 44.56	$ 8.34
2025	$ 42.02	$ 8.55

Assuming a discount rate of 10%, the detailed calulation of TRC benefits for a 15 watt compact fluorescent bulb are shown below.

TRC Benefits Detailed Calculation

= **Year 1 Avoided Electricity Costs** {(15.5 kWh x $0.124) + (7.7 kWh x $0.0843) + (20.3 kWh x $0.0452) + (0.0 kWh x $0.1115) + (11.7 kWh x $0.0796) + (14.0 kWh x $0.0459) + (17.5 kWh x $0.0814) + (17.7 kWh x $0.0408)} x 1.00 **(discount factor[4])**
+ Year 2 Avoided Electricity Costs {(15.5 kWh x $0.1154) + (7.7 kWh x $0.0868) + (20.3 kWh x $0.0489) + (0.0 kWh x $0.1106) + (11.7 kWh x $0.0836) + (14.0 kWh x $0.0501) + (17.5 kWh x $0.0904) + (17.7 kWh x $0.0449)} x 0.909091 **(discount factor)**
+ Year 3 Avoided Electricity Costs {(15.5 kWh x $0.1119) + (7.7 kWh x $0.0771) + (20.3 kWh x $0.0489) + (0.0 kWh x $0.1045) + (11.7 kWh x $0.0795) + (14.0 kWh x $0.0476) + (17.5 kWh x $0.0858) + (17.7 kWh x $0.0434)} x 0.826446 **(discount factor)**
+ **Year 4 Avoided Electricity Costs** (15.5 kWh x $0.113) + (7.7 kWh x $0.0774) + (20.3 kWh x $0.0521) + (0.0 kWh x $0.107.0) + (11.7 kWh x $0.0805) + (14.0 kWh x $0.0482) + (17.5 kWh x $0.0835) + (17.7 kWh x $0.0434)]} x 0.751315 **(discount factor)**

= $25.43 (Note that this is the sum of the 4 years of discounted results).

Step Two – Calculating TRC Costs

TRC costs represent a discounted stream of increased electricity costs, other fuel costs, participant (customer) and utility costs. In practice, participant costs and utility costs are most commonly applied. In the case of a 15 watt compact fluorescent bulb, there is no increased electricity or other fuel costs. There are however participant costs of $2.00 as shown in Table 4.2. This cost is a one-time cost that occurs in Year 1. As such no discounting is applied.

[4] A discount factor is calculated using the net present value formula [1/(1+discount rate)^(term-1)]. For example, using a discount rate of 10%, in year 3 the discount factor is 1/(1.1)^(3-1) = 0.826446

Step Three – Calculating TRC Net Benefits and Benefit-Cost Ratio

Once TRC benefits and TRC costs have been generated the calculation of TRC net benefits and benefit-cost ratio can be easily derived. The TRC net benefits are simply the difference between the TRC benefits and the TRC costs and the TRC benefit-cost ratio is the TRC benefits divided by TRC costs.

Using the 15 watt compact fluorescent bulb example, the calculation of TRC net benefits and benefit-cost ratio are shown below.

TRC Net Benefits = $25.43 - $2.00 = **$23.43**

TRC Benefit-Cost Ratio = $25.43 / $2.00 = **12.71**

Technology Example 2: ***Water Heating Load Shifting – Utility Controlled Relay***

Step One – Calculating TRC Benefits

The prescribed savings for a utility controlled relay, the assumed electricity energy and demand savings and other technology inputs are shown in the tables below:

Table 4.5 Unit Electricity Energy and Demand Savings

	TRC INPUTS								
Technology	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Utility Controlled Relay	1133.9	-1133.9	0.0	647.9	-427.0	-220.0	0.0	0.0	0.777

Table 4.6 Other Technology Inputs Required for Calculating TRC Benefits

	TRC INPUTS						
Technology	Technology Information		Unit Energy Savings				
	Measure Life	Customer Unit Incremental Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Utility Controlled Relay	12	$50.00	0.00	0.00	0.00	0.00	0.00

Assuming a discount rate of 10%, the detailed calulation of TRC benefits for a utility controlled relay are shown below.

TRC Benefits Detailed Calculation

= **Year 1 Avoided Electricity Costs** {(1133.9 kWh x $0.124) + (-1133.9 kWh x $0.0843) + (0.0 kWh x $0.0452) + (647.9 kWh x $0.1115) + (-427.0 kWh x $0.0796) + (-220.0 kWh x $0.0459) + (0.0 kWh x $0.0814) + (0.0 kWh x $0.0408) + (0.777 kW x $0.00) + (0.777 kW x $0.00)} x 1.00 (discount factor)
+ Year 2 Avoided Electricity Costs {(1133.9 kWh x $0.1154) + (-1133.9 kWh x $0.0868) + (0.0 kWh x $0.0489) + (647.9 kWh x $0.1106) + (-427.0 kWh x $0.0836) + (-220.0 kWh x $0.0501) + (0.0 kWh x $0.0904) + (0.0 kWh x $0.0449) + (0.777 kW x $74.65) + (0.777 kW x $5.62)} x 0.909091 (discount factor)
+ Year 3 Avoided Electricity Costs {(1133.9 kWh x $0.1119) + (-1133.9 kWh x $0.0771) + (0.0 kWh x $0.0489) + (647.9 kWh x $0.1045) + (-427.0 kWh x $0.0795) + (-220.0 kWh x $0.0476) + (0.0 kWh x $0.0858) + (0.0 kWh x $0.0434) + (0.777 kW x $83.57) + (0.777 kW x $5.76)} x 0.826446 (discount factor)
+ **Year 4 Avoided Electricity Costs** {(1133.9 kWh x $0.1135) + (-1133.9 kWh x $0.0774) + (0.0 kWh x $0.0521) + (647.9 kWh x $0.1070) + (-427.0 kWh x $0.0805) + (-220.0 kWh x $0.0482) + (0.0 kWh x $0.0835) + (0.0 kWh x $0.0434) + (0.777 kW x $71.49) + (0.777 kW x $5.90)} x 0.751315 (discount factor)
+ **Year 5 Avoided Electricity Costs** {(1133.9 kWh x $0.1102) + (-1133.9 kWh x $0.0773) + (0.0 kWh x $0.0527) + (647.9 kWh x $0.1032) + (-427.0 kWh x $0.0813) + (-220.0 kWh x $0.0485) + (0.0 kWh x $0.0842) + (0.0 kWh x $0.0430) + (0.777 kW x $85.42) + (0.777 kW x $6.05)} x 0.683013 (discount factor) +
Year 6 Avoided Electricity Costs {(1133.9 kWh x $0.1124) + (-1133.9 kWh x $0.0789) + (0.0 kWh x $0.0533) + (647.9 kWh x $0.1131) + (-427.0 kWh x $0.0846) + (-220.0 kWh x $0.0512) + (0.0 kWh x $0.0885) + (0.0 kWh x $0.0478) + (0.777 kW x $81.20) + (0.777 kW x $6.20)} x 0.620921 (discount factor)
+ **Year 7 Avoided Electricity Costs** {(1133.9 kWh x $0.1252) + (-1133.9 kWh x $0.0864) + (0.0 kWh x $0.0599) + (647.9 kWh x $0.1169) + (-427.0 kWh x $0.0913) + (-220.0 kWh x $0.0540) + (0.0 kWh x $0.0925) + (0.0 kWh x $0.0519) + (0.777 kW x $61.60) + (0.777 kW x $6.36)} x 0.564474 (discount factor)
+ **Year 8 Avoided Electricity Costs** {(1133.9 kWh x $0.1257) + (-1133.9 kWh x $0.0924) + (0.0 kWh x $0.0628) + (647.9 kWh x $0.1279) + (-427.0 kWh x $0.0968) + (-220.0 kWh x $0.0567) + (0.0 kWh x $0.0989) + (0.0 kWh x $0.0544) + (0.777 kW x $46.63) + (0.777 kW x $6.52)} x 0.513158 (discount factor)
+ **Year 9 Avoided Electricity Costs** {(1133.9 kWh x $0.1274) + (-1133.9 kWh x $0.0947) + (0.0 kWh x $0.0696) + (647.9 kWh x $0.1516) + (-427.0 kWh x $0.1067) + (-220.0 kWh x $0.0625) + (0.0 kWh x $0.1028) + (0.0 kWh x $0.0599) + (0.777 kW x $23.16) + (0.777 kW x $6.68)} x 0.466507 (discount factor)
+ **Year 10 Avoided Electricity Costs** {(1133.9 kWh x $0.1317) + (-1133.9 kWh x $0.0973) + (0.0 kWh x $0.0709) + (647.9 kWh x $0.1525) + (-427.0 kWh x $0.1081) + (-220.0 kWh x $0.0639) + (0.0 kWh x $0.1045) + (0.0 kWh x $0.0614) + (0.777 kW x $26.88) + (0.777 kW x $6.85)} x 0.424098 (discount factor)
+ **Year 11 Avoided Electricity Costs** {(1133.9 kWh x $0.1360) + (-1133.9 kWh x $0.1000) + (0.0 kWh x $0.0721) + (647.9 kWh x $0.1535) + (-427.0 kWh x $0.1095) + (-220.0 kWh x $0.0653) + (0.0 kWh x $0.1062) + (0.0 kWh x $0.0628) + (0.777 kW x $29.94) + (0.777 kW x $7.02)} x 0.385543 (discount factor)
+ **Year 12 Avoided Electricity Costs** {(1133.9 kWh x $0.1403) + (-1133.9 kWh x $0.1027) + (0.0 kWh x $0.0734) + (647.9 kWh x $0.1544) + (-427.0 kWh x $0.1109) + (-220.0 kWh x $0.0668) + (0.0 kWh x $0.1080) + (0.0 kWh x $0.0643) + (0.777 kW x $31.66) + (0.777 kW x $7.19)} x 0.350494 (discount factor)

= $884.63 (Note that this is the sum of the 12 years of discounted results).

Step Two – Calculating TRC Costs

In the case of a utility controlled relay, there is no increased electricity or other fuel costs. There are however participant costs of $50.00 as shown in Table 4.6.[5] This cost is a one-time cost that occurs in Year 1. As such no discounting is applied.

Step Three – Calculating TRC Net Benefit and Benefit-Cost Ratio

TRC Net Benefits = $884.63 - $50.00 = **$834.63**

TRC Benefit-Cost Ratio = $884.63 / $50.00 = **17.69**

[5] Note that many distributors are now offering utility controlled relays for water heaters. These units may have a cost different to that prescribed by the Board's Assumptions and Measures List. In these cases, it is appropriate to use the "real cost" in the TRC assessment.

Technology Example 3: *Energy Efficient Showerhead*

Step One – Calculating TRC Benefits

The prescribed savings for an efficient showerhead, the assumed electricity energy and demand savings and other technology inputs are shown in the tables below:

Table 4.7 Unit Electricity Energy and Demand Savings

Technology	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Efficient Showerhead	37.5	42.8	100.5	32.5	48.8	101.1	81.3	101.1	0.039

Table 4.8 Other Technology Inputs Required for Calculating TRC Benefits

Technology	TRC INPUTS						
	Technology Information		Unit Energy Savings				
	Measure Life	Customer Unit Incremental Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Efficient Showerhead	12	$7.00	0.00	26.80	0.00	0.00	0.00

Assuming a discount rate of 10%, the detailed calulation of TRC benefits for an efficient showerhead are shown below.

TRC Benefits Detailed Calculation

a) Electricity Savings

= **Year 1 Avoided Electricity Costs** {(37.5 kWh x $0.124) + (42.8 kWh x $0.0843) + (100.5 kWh x $0.0452) + (32.5 kWh x $0.1115) + (48.8 kWh x $0.0796) + (101.1 kWh x $0.0459) + (83.3 kWh x $0.0814) + (101.1 kWh x $0.0408) + (0.039 kW x $0.00) + (0.039 kW x $0.00)} x 1.00 (discount factor)
+ Year 2 Avoided Electricity Costs {(37.5 kWh x $0.1154) + (42.8 kWh x $0.0868) + (100.5 kWh x $0.0489) + (32.5 kWh x $0.1106) + (48.8 kWh x $0.0836) + (101.1 kWh x $0.0501) + (83.3 kWh x $0.0904) + (101.1 kWh x $0.0449) + (0.039 kW x $74.65) + (0.039 kW x $5.62)} x 0.909091 (discount factor)
+ Year 3 Avoided Electricity Costs {(37.5 kWh x $0.1119) + (42.8 kWh x $0.0771) + (100.5 kWh x $0.0489) + (32.5 kWh x $0.1045) + (48.8 kWh x $0.0795) + (101.1 kWh x $0.0476) + (83.3 kWh x $0.0858) + (101.1 kWh x $0.0434) + (0.039 kW x $83.57) + (0.039 kW x $5.76)} x 0.826446 (discount factor)
+ **Year 4 Avoided Electricity Costs** {(37.5 kWh x $0.1135) + (42.8 kWh x $0.0774) + (100.5 kWh x $0.0521) + (101.1 kWh x $0.1070) + (48.8 kWh x $0.0805) + (101.1 kWh x $0.0482) + (83.3 kWh x $0.0835) + (101.1 kWh x $0.0434) + (0.039 kW x $71.49) + (0.039 kW x $5.90)} x 0.751315 (discount factor)
+ **Year 5 Avoided Electricity Costs** {(37.5 kWh x $0.1102) + (42.8 kWh x $0.0773) + (100.5 kWh x $0.0527) + (101.1 kWh x $0.1032) + (48.8 kWh x $0.0813) + (101.1 kWh x $0.0485) + (83.3 kWh x $0.0842) + (101.1 kWh x $0.0430) + (0.039 kW x $85.42) + (0.039 kW x $6.05)} x 0.683013 (discount factor)

+ **Year 6 Avoided Electricity Costs** {(37.5 kWh x $0.1124) + (42.8 kWh x $0.0789) + (100.5 kWh x $0.0533) + (101.1 kWh x $0.1131) + (48.8 kWh x $0.0846) + (101.1 kWh x $0.0512) + (83.3 kWh x $0.0885) + (101.1 kWh x $0.0478) + (0.039 kW x $81.20) + (0.039 kW x $6.20)} x 0.620921 (discount factor)
+ **Year 7 Avoided Electricity Costs** {(37.5 kWh x $0.1252) + (42.8 kWh x $0.0864) + (100.5 kWh x $0.0599) + (101.1 kWh x $0.1169) + (48.8 kWh x $0.0913) + (101.1 kWh x $0.0540) + (83.3 kWh x $0.0925) + (101.1 kWh x $0.0519) + (0.039 kW x $61.60) + (0.039 kW x $6.36)} x 0.564474 (discount factor)
+ **Year 8 Avoided Electricity Costs** {(37.5 kWh x $0.1257) + (42.8 kWh x $0.0924) + (100.5 kWh x $0.0628) + (101.1 kWh x $0.1279) + (48.8 kWh x $0.0968) + (101.1 kWh x $0.0567) + (83.3 kWh x $0.0989) + (101.1 kWh x $0.0544) + (0.039 kW x $46.63) + (0.039 kW x $6.52)} x 0.513158 (discount factor)
+ **Year 9 Avoided Electricity Costs** {(37.5 kWh x $0.1274) + (42.8 kWh x $0.0947) + (100.5 kWh x $0.0696) + (101.1 kWh x $0.1516) + (48.8 kWh x $0.1067) + (101.1 kWh x $0.0625) + (83.3 kWh x $0.1028) + (101.1 kWh x $0.0599) + (0.039 kW x $23.16) + (0.039 kW x $6.68)} x 0.466507 (discount factor)
+ **Year 10 Avoided Electricity Costs** {(37.5 kWh x $0.1317) + (42.8 kWh x $0.0973) + (100.5 kWh x $0.0709) + (32.5 kWh x $0.1525) + (48.8 kWh x $0.1081) + (101.1 kWh x $0.0639) + (83.3 kWh x $0.1045) + (101.1 kWh x $0.0614) + (0.039 kW x $26.88) + (0.039 kW x $6.85)} x 0.424098 (discount factor)
+ **Year 11 Avoided Electricity Costs** {(37.5 kWh x $0.1360) + (42.8 kWh x $0.1000) + (100.5 kWh x $0.0721) + (32.5 kWh x $0.1535) + (48.8 kWh x $0.1095) + (101.1 kWh x $0.0653) + (83.3 kWh x $0.1062) + (101.1 kWh x $0.0628) + (0.039 kW x $29.94) + (0.039 kW x $7.02)} x 0.385543 (discount factor)
+ **Year 12 Avoided Electricity Costs** {(37.5 kWh x $0.1403) + (42.8 kWh x $0.1027) + (100.5 kWh x $0.0734) + (32.5 kWh x $0.1544) + (48.8 kWh x $0.1109) + (101.1 kWh x $0.0668) + (83.3 kWh x $0.1080) + (101.1 kWh x $0.0643) + (0.039 kW x $31.66) + (0.039 kW x $7.19)} x 0.350494 (discount factor)

= $ 317.14 (Note that this is the sum of the 12 years of discounted results).

b) Water Savings

Assuming a water rate of $87.60/m3 in year 2007 and an escalation rate of 2% the avoided water cost are shown in table 4.9.

Table 4.9 Sample Avoided Water Rates

Year	Sample Avoided Water Costs $/m3	
	Water Rate	
2007	$	0.8760
2008	$	0.8935
2009	$	0.9114
2010	$	0.9296
2011	$	0.9482
2012	$	0.9672
2013	$	0.9865
2014	$	1.0062
2015	$	1.0264
2016	$	1.0469
2017	$	1.0678
2018	$	1.0892
2019	$	1.1110
2020	$	1.1332
2021	$	1.1559
2022	$	1.1790
2023	$	1.2026
2024	$	1.2266
2025	$	1.2511

= **Year 1 Avoided Water Costs** 26.8 m3 x $0.8760 x 1.00 (discount factor)
+ Year 2 Avoided Water Costs 26.8 m3 x $0.8935 x 0.909091 (discount factor)
+ Year 3 Avoided Water Costs 26.8 m3 x $0.9114 x 0.826446 (discount factor)
+ Year 4 Avoided Water Costs 26.8 m3 x $0.9296 x 0.751315 (discount factor)
+ **Year 5 Avoided Water Costs** 26.8 m3 x $0.9482 x 0.683013 (discount factor)
+ **Year 6 Avoided Water Costs** 26.8 m3 x $0.9672 x 0.620921 (discount factor)
+ **Year 7 Avoided Water Costs** 26.8 m3 x $1.0062 x 0.564474 (discount factor)
+ **Year 8 Avoided Water Costs** 26.8 m3 x $1.0264 x 0.513158 (discount factor)
+ **Year 9 Avoided Water Costs** 26.8 m3 x $1.0469 x 0.466507 (discount factor)
+ **Year 10 Avoided Water Costs** 26.8 m3 x $1.0678 x 0.424098 (discount factor)
+ **Year 11 Avoided Water Costs** 26.8 m3 x $1.0892 x 0.385543 (discount factor)
+ **Year 12 Avoided Water Costs** 26.8 m3 x $1.1110 x 0.350494 (discount factor)

= $ 190.60 (Note that this is the sum of the 12 years of discounted results).

Total TRC Benefits = Avoided Electricity Costs + Avoided Water Costs
= $ 317.14 + $190.60
= $ 507.74

Step Two – Calculating TRC Costs

In the case of an energy efficient showerhead, there is no increased electricity or other fuel costs. There are however participant costs of $7.00 as shown in Table 4.8. This cost is a one-time cost that occurs in Year 1. As such no discounting is applied.

Step Three – Calculating TRC Net Benefits and Benefit-Cost Ratio

TRC Net Benefits = $507.74 - $7.00 = **$500.74**

TRC Benefit-Cost Ratio = $507.74 / $7.00 = **72.53**

3.2 Program Screening Analysis

Once a measure has passed the technology screening analysis, the analyst may wish to design a program that uses the technology. The program screening analysis combines the results of the individual technology analysis with the key program components, including number of participants, free ridership rates and direct distributor program costs. The program screening analysis repeats the same approach as defined above with the inclusion of the adjustment factors to assess the measure at the program level.

Detailed examples are set out below.

Program Example 1: ***Residential Energy Audit Campaign***

Using the compact fluorescent bulb and showerhead technologies described earlier, assume a utility has designed a residential energy audit program. The program provides the participant with an energy audit at a cost of $100 and in return the participant receives a report highlighting potential energy saving opportunities along with two free 15 watt CFLs and an energy efficient showerhead.

The utility is expecting 100 participants in the first year. Given the program design, free ridership is expected to be 10%. This means that 10% of the participants would have undertaken an energy audit on their own in the absence of the program. The utility's cost for running the program is estimated at $30,000, which includes the cost of designing, marketing, operating and evaluating the program, as well as the cost of the CFL bulbs and showerheads provided to the customer.[6]

Tables 4.10 and 4.11 provide the key inputs required for undertaking the TRC test, including per unit savings, number of participants, free ridership, measure life, customer equipment cost and alternative resource savings. Program costs of $30,000 are shown as a single line item.

Table 4.10 Program Electricity Energy and Demand Savings

Technology	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Energy Audit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000
15 W CFL	15.5	7.7	20.3	0.0	11.7	14.0	17.5	17.7	0.000
Efficient Showerhead	37.5	42.8	100.5	32.5	48.8	101.1	81.3	101.1	0.039
Program Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000

Table 4.11 Other Program Inputs Required for Calculating TRC Benefits

Technology	TRC INPUTS									
	Technology Information					Unit Energy Savings				
	Participants [gross]	Free Ridership %	Measure Life	Customer Unit Incremental Costs	Program Delivery Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Energy Audit	100	10.0%	0	$100.00	$ -	0.00	0.00	0.00	0.00	0.00
15 W CFL	200	10.0%	4	$0.00	$ -	0.00	0.00	0.00	0.00	0.00
Efficient Showerhead	100	10.0%	12	$0.00	$ -	0.00	26.80	0.00	0.00	0.00
Program Costs	-	0.0%	0	$0.00	$ 30,000.00	0.00	0.00	0.00	0.00	0.00

Step One – Calculating TRC Benefits

Energy Audit TRC Benefits = $0

15 Watt CFL TRC Benefits[7] = $ 25.43 x 200 bulbs x (1-freeridership)
= $ 4,577.40

[6] While CFLs and showerheads are most often installed by the participant and not the utility, according to the TAG™ Technical Assessment Guide Volume 4 Revision: Fundamentals and Methods, End Use, Prepared by Barakat and Chamberlin Inc., January 1991, a distributor can often use its volume-buying capacity to receive measures at reduced costs.

[7] See calculating TRC benefits in technology example 1.

Efficient Showerhead TRC Benefits[8] = $ 507.74 x 100 showerheads x (1-freeridership)
= $ 45,696.60

Total Program TRC Benefits = $ 4,577.40 + $ 45,696.60
= $ 50,274

Step Two – Calculating TRC Costs

a. Customer Equipment Costs

Energy Audit TRC Costs = $100 x 100 audits x (1-freeridership)
= $9,000

15 Watt CFL TRC Costs[9] = $ 0 x 200 bulbs x (1-freeridership)
= $ 0

Efficient Showerhead TRC Costs[10] = $ 0 x 100 x (1-freeridership)
= $ 0

Program Costs = $ 30,000

Total Program TRC Costs = $ 9,000 + $30,000
= $ 39,000

Step Three – Calculating TRC Net Benefits and Benefit-Cost Ratio

TRC Net Benefits = $50,274 - $39,000 = **$11,274**

TRC Benefit-Cost Ratio = $50,274/ $39,000 = **1.29**

Program Example 2: ***Residential Demand Response Program***

Using the utility controlled relay unit described earlier, assume a utility has designed a residential demand response program. The program encourages participants to install a utility controlled relay on their water heater. In exchange for participating in the program the participant receives a $25 voucher or coupon.

The utility expects 1,000 participants to enroll in the first year. The utility believes that in the absence of the program no customers would install the unit and therefore assumes a program free ridership rate of 0%. The utility's cost for operating the program is assumed to be $475,000 which includes: equipment and installation; control systems; a $25 gift card: and program marketing and administration. Note that for the purposes of this analysis, the cost of the equipment is included in the program costs; as such customer equipment costs are reported as $0 in the TRC test. In practice, from the perspective of

[8] See calculating TRC benefits in technology example 3.
[9] Utility is giving away CFLs. Costs of bulbs are included in program costs.
[10] Utility is giving away showerheads. Costs of showerheads are included in program costs.

the TRC test it does not matter if the equipment costs are calculated as customer equipment costs, or included as program costs, as long as they are properly accounted for.[11]

Tables 4.12 and 4.13 provide the key inputs required for undertaking the TRC test, including per unit savings, number of participants, free ridership, measure life, customer equipment cost and alternative resource savings. Program costs of $475,000 are shown as a single line item.

[11] According to the TAG™ Technical Assessment Guide Volume 4 Revision: Fundamentals and Methods, End Use, Prepared by Barakat and Chamberlin Inc., January 1991, utility equipment costs include the cost of any utility devices needed to operate the program as well as any CDM measure directly installed by the utility. Programs most often requiring utility expenditure for CDM measures are load management programs such as a direct load control.

Table 4.12 Program Electricity Energy and Demand Savings

Technology	TRC INPUTS								
	Unit Electricity Savings								
	Electricity Savings								
	Winter			Summer			Shoulder		
	On Peak kWh	Mid Peak kWh	Off Peak kWh	On Peak kWh	Mid Peak kWh	Off Peak kWh	Mid Peak kWh	Off Peak kWh	Peak Demand Savings (Summer kW)
Utility Controlled Relay	1133.9	-1133.9	0.0	647.9	-427.0	-220.0	0.0	0.0	0.777
Program Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000

Table 4.13 Other Program Inputs Required for Calculating TRC Benefits

Technology	TRC INPUTS									
	Technology Information					Unit Energy Savings				
	Participants [gross]	Free Ridership %	Measure Life	Customer Unit Incremental Costs	Program Delivery Costs	Unit Annual Gas Savings m3	Unit Water Savings m3 (000's litres)	Unit Propane Savings m3 (000's litres)	Unit Oil Savings litres	Unit Diesel Savings m3
Utility Controlled Relay	1,000	0.0%	12	$0.00	$ -	0.00	0.00	0.00	0.00	0.00
Program Costs	-	0.0%	0	$0.00	$ 475,000.00	0.00	0.00	0.00	0.00	0.00

Step One – Calculating TRC Benefits

Utility Controlled Relay Unit TRC Benefits[12] = $884.63 x 1,000 units x (1- freeridership)
= $ 884,630

Step Two – Calculating TRC Costs

b. Customer Equipment Costs

Utility Controlled Relay TRC Costs[13] = $ 0 x 1,000 units x (1-freeridership)
= $ 0

Program Costs = $ 475,000

Total Program TRC Costs = $ 0 + $475,000
= $ 475,000

Step Three – Calculating TRC Net Benefit and Benefit-Cost Ratio

TRC Net Benefits = $884,630 - $475,000 = **$409,630**

TRC Benefit-Cost Ratio = $884,630 / $475,000 = **1.86**

[12] See calculating TRC benefits in technology example 2.
[13] See calculating TRC costs in technology example 2.

3.3 Portfolio Screening Analysis

Once the distributor has screened all of its programs and is comfortable with the program designs, the overall cost effectiveness of the portfolio needs to be tested. To do this, the distributor will sum the program TRC results and then allocate administrative and any indirect costs to the entire portfolio. Administrative costs include overhead, monitoring and evaluation costs and administration costs associated with the delivery of the overall CDM portfolio. This roll-up value represents the TRC result for the entire CDM programming activity.

Portfolio Example: ***Portfolio Screening Analysis***

Assuming a distributor planned to deliver only the two programs outlined above; the following consists of a theoretical portfolio screening analysis.

Assuming a distributor has indirect costs of administration, market support, overhead and monitoring and evaluation of $50,000. The NPV of the portfolio would be as follows:

Program 1 NPV Program:	11,274
Program 2 NPV Program:	409,630
Total Indirect Costs:	(50,000)
NPV_{TRC}	340,904

Therefore, the NPV_{TRC} of this portfolio is $340,904.

3.4 Using TRC Analysis for Post Program Evaluation

The TRC calculation done at the end of a program year follows exactly the same approach using the “actual” information collected as part of the tracking and reporting exercises as opposed to estimates.

4.0 Symbols Used in the TRC Guidelines

The following is a summary of all of the symbols used in the TRC Guidelines:

NPV = net present value
NPV_{TRC} = net present value of total resource cost calculation
B_{TRC} = present value of total resource cost benefits
C_{TRC} = present value of total resource cost costs
AC_t = avoided resource costs in year t
UC_t = distributor program costs in year t
PC_t = participant costs in year t
N = number of years use in the analysis
d = discount rate used in the analysis
INC_t = incentive amount provided by the distributor in year t
UATES = unit annual total energy savings
NUD = number of units delivered or installed
NUD_{sa} = number of units delivered or installed in an distributors service area
FRR = free rider rate
AR = attribution rate
AS = attributable savings
$NPV_{technology}$ = net present value of the technology at the technology screening level
$NPV_{program}$ = net present value of the program

APPENDIX B:

Guidelines for the Application of Fully Allocated Costing

Appendix B - Guidelines for the Application of Fully-Allocated Costing for CDM Activities

1. INTRODUCTION

The Board has determined that a fully allocated costing methodology must be applied to all CDM activities. This Appendix provides information on how distributors should apply a fully allocated costing approach.

A fully allocated costing methodology results in the allocation of direct costs and of a proportional share of indirect costs. This methodology would, for example, include a proportional allocation of employee benefits (e.g. health insurance) for time and efforts spent in relation to CDM activities.

For CDM activities funded by the OPA, the direct costs and the proportional share of the indirect costs attributable to OPA-funded CDM activities should be removed from the distributor's distribution rates, and more appropriately recovered through the distributor's OPA-funded CDM activities. This is necessary to avoid double-counting, since all existing direct and indirect costs are included in distribution rates.

For CDM activities funded through distribution rates, a fully allocated costing approach is also required but costs will continue to be included in distribution rates. The use of fully allocated costing will ensure that programs are cost effective since the full costs incurred to undertake CDM activities are included in the cost-benefit analysis.

2. COST ALLOCATION PROCESS

Fully allocated costs are the sum of ***marginal costs (direct costs)*** and ***allocable costs*** (**or *indirect costs***). These costs are defined as follows:

Marginal costs - Those costs which would be eliminated or reduced if the CDM activities as a whole were no longer undertaken.

Allocable costs - Those costs which would be incurred regardless of whether or not the CDM activities were undertaken.

Marginal costs can be directly assigned to CDM activities. Allocable or indirect costs must be allocated, using a cost driver, to determine the proportional share of the indirect costs attributable to CDM activities.

2.1 Activity Analysis

In order to determine the costs associated with CDM activities, distributors should use an activity analysis process to assess the nature and extent of the functions being performed throughout the distribution company to undertake the CDM activities, and the links between these functions and the underlying costs. The link is referred to as a ***cost driver***. A ***cost driver*** is a measure used to allocate, to a CDM activity, the costs of any functions performed within the distribution company to undertake the CDM activity. The analysis should include the identification of all activities performed within the distribution company, whether or not these activities directly or indirectly support CDM activities. This provides a complete activity profile of the distribution company, thereby providing the basis for a complete and reasonable allocation of costs.

Distributors will need to make a determination on the appropriate level of detail used in the activity analysis. Consideration of the costs associated with a finer activity breakdown in comparison to the benefits to be gained must be made.

2.2 Costs to Include

The activity analysis should include, for the purposes of cost allocation, direct and indirect costs such as:

- All Salaries (including supervisory, weekly, hourly and part time labour costs)
- Employee benefits
- Paid overtime
- Employee expenses
- Billing and Collection
- Community Relations
- Administration and General expenses
- IT costs
- Office and Computer equipment

This list is not an exhaustive. There may be other costs that need to be considered.

The remainder of this document deals with the allocation of allocable or indirect costs.

2.3 Cost Drivers for Allocable Costs

To complete the activity analysis, a distributor must determine an appropriate cost driver for each activity not directly related to CDM.

Cost drivers should be:

- Representative of how costs are being incurred;
- Implemented in a cost effective manner; and
- Understandable.

Generally, the nature of the activities will need to be assessed in order to select an appropriate cost driver. As discussed below, cost drivers include headcount, time, and volume of activity.

2.3.1 Headcount as a Driver

A common cost driver used to allocate salaries and other labour-related costs is headcount. This driver is based on the number of full time equivalents (FTE) needed to support CDM activities. ***FTEs*** are a measure of labour effort devoted to an activity. For example, if six people each devoted 25% of their time to an activity, the full time equivalent for that activity would be 1.5 FTEs. Part time positions need to be converted into full time equivalents. For example, if an employee works 3 days per week, the full time equivalent would be 0.6 FTE. The allocated FTEs provide the basis to allocate employee related costs such as employee benefits, paid overtime, employee expenses, or employee related support activities such as Human Resources.

Activities for which a headcount driver is appropriate also include activities that generally support employees in the performance of their duties and are used equally by each employee. Examples of activities where use of a headcount driver may be appropriate for the determination of fully allocated costs are payroll, IT services, and computer and office equipment.

2.3.2 Time as a Driver

Time can also be used as a cost driver for activities such as executive and administrative functions, legal services, and financial analysis. While these functions may not be directly involved in the day-to-day activities related to CDM, the executive and administrative functions, for example, may oversee, and support, respectively, other functions within the distribution company that are directly involved in CDM activities. These functions generally lend themselves to time reporting as they are typically project specific. The use of time is considered practical and appropriate in these cases since it provides a strong link to the incurrence of costs.

In order to calculate the percentage of time to be allocated to CDM activities, the base hours per employee must be determined. The base hours subject to allocation must include only those hours which can be considered to be available for work, including overtime. This ensures that all the costs of an employee, such as vacation or training days, are equally shared across all hours worked.

2.3.3 Number or Frequency of Activity as a Driver

Some activities can be repetitive in nature and consistent over time in terms of the level of effort required to provide service. Examples of such activities might include payroll processing, customer care, and accounts payable. As such, they can be allocated based on the number of events reflecting or causing the activity to be performed and, therefore, the cost to be incurred.

For example, call centre costs could be allocated based on number of calls received in relation to CDM activities, and accounts payable processing costs could be allocated based on the number of CDM invoices processed.

2.3.4 Composite Ratio as a Driver

A ***composite ratio*** is a cost driver which allocates the cost of an activity on the same basis as the allocation of one or more other activities. A composite ratio is normally used to allocate the cost of an activity which supports other activities.

A composite ratio could be used, for example, to allocate the costs of an administrative or general function which support the entire organization. For instance, if the cost drivers described above result in an allocation of 5% of the total operating, maintenance and administration expenses being allocated to CDM activities, then this ratio could be used to allocate the costs of the administrative or general function.

APPENDIX C:

Input Assumptions Template

Appendix C: Input Assumptions Template

Efficient Technology & Equipment Description
What equipment/technology is being installed?
Base Technology & Equipment Description
What equipment/technology would otherwise have been installed?

Resource Savings Assumptions

Electricity	***kW or kWh***
Description of how electricity savings assumptions where determined.	
Natural Gas	***m^3 or Btu or CFM***
Where applicable. Description of how natural gas savings assumptions where determined.	
Water	***L***
Where applicable. Description of how water savings assumptions where determined.	

Other Input Assumptions

Equipment Life	***years***
What is the estimated service life of the equipment?	
Incremental Cost	***$/kW or $/kWh***
What is the difference in cost between the efficient equipment/technology and the base equipment/technology?	
Free Ridership	***%***
What is the appropriate free ridership rate for a program using this equipment/technology?	

APPENDIX F

2005 – OEB CDM Annual Report

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March 30, 2006

Delivered by Courier

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Attention: Mr. John Zych
Board Secretary

Re: Haldimand County Hydro Inc.
RP-2004-0203 \ EB-2004-0523
Conservation and Demand Annual Report – 2005

Further to the Ontario Energy Board's (the "Board") orders approving electricity distributor conservation and demand ("CDM") plans, the Board requires that each distributor file an annual report including a cost benefit analysis.

Pursuant to the Board's "*Guideline for Annual Reporting of CDM Initiatives*" issued December 21, 2005, please find enclosed five (5) hard copies and two (2) electronic copies of Haldimand County Hydro Inc.'s 2005 annual reporting which includes the following:

- Letter, dated March 31, 2006, from J. Albert on behalf of the NEPPA CDM Working Group;
- 2005 Conservation and Demand Management Annual Report, dated March 31, 2006;
- Appendix A – Evaluation of the CDM Plan;
- Appendix B – Discussion of the Program "Lighten Your Electricity Bill"; and
- Reporting Tool, "Energy and Demand Savings", prepared in conjunction with Appendices A and B

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by J.A. Scott

Jacqueline A. Scott
Finance Manager

March 31, 2006

Board Secretary at Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Suite 2700
Toronto, ON
M4P 1E4

2005 Annual Conservation and Demand Management Report
RP-2004-0203 / EB 2004-0523

On December 9, 2004 Niagara Erie Public Power Alliance (NEPPA)[1] members filed their plans to implement conservation and demand management programs. During plan preparations, concerted effort amongst the group to organize and share initiatives when ever possible to share costs and improve the overall consistency of programming.

Some key joint initiatives have included

1. Conserver Joe – Family Education Package
    a. Handbook
    b. Bill Inserts
    c. Newsletters
    d. Print Ads
    e. Website
2. RFP process to select qualified commercial/agricultural and industrial auditors
3. Participation is provincial coupon campaigns.
    a. Lighten Your Electricity Bill
    b. Cold Water Wash
4. Training and Development
5. LED Traffic Lights

[1] NEPPA comprising Canadian Niagara Power Inc. Grimsby Power Inc., Haldimand County Hydro Inc. Niagara Falls Hydro Inc., Niagara On The Lake Hydro Inc., Norfolk Power Distribution Inc., Peninsula West Utilities, St. Catharines Hydro Utility Services Inc., and Welland Hydro-Electric System Corp., Brant County Power, Brantford Power.

How Did We Do?

Collectively our NEPPA members contributed to annual energy savings of **5,383,735.54** kWh and demand savings of **2292.73** kW [2].

Energy reductions occurred from a variety of programming both through joint initiatives and localized community programming.

Opportunities

As we develop a conservation culture in Ontario we must continue to balance the need for short-term results while fostering a long-term conservation attitude among the citizens and businesses in the province. The industry must continue to coordinate its efforts to ensure that program delivery is efficient and available to all customers. Our goal should be rapid program deployment and using the LDC's clear channel to market. Clarity regarding the roles of the LDC's, OPA, IESO, etc. would be beneficial in this regard.

Further, clarity on the topics of LDC cost recovery, lost revenues, and criteria for assessing prudence of CDM spending would also be helpful. This will lead to more aggressive applications for second generation funding. At all times, we must strive to minimize bureaucracy wherever possible. For example, the opportunity to determine and agree on effective conservation programs up front should minimize the measurement and verification efforts required to substantiate these same programs at their conclusion.

Our commitment remains firm of remaining an active participant and advocacy of developing and promoting a conservation culture in Ontario.

Regards,

NEPPA Member
R. Jane Albert
Consumer Services Manager
Chair Person, NEPPA CDM Working Group
Haldimand County Hydro Inc.

[2] Energy Saved does not include data from St. Catharine's Hydro as they submitted a joint data statement with the CLD group to share collective results. At time of this report we were still waiting for Penwest, Fortis and Brantford to report their Kwh & Kw numbers therefore the numbers shown are incomplete from a complete NEPPA Collective Reporting.

2005 OEB Annual

Conservation and Demand Management Report

Submitted By Haldimand County Hydro Inc.

RP-2004-0203/EB-2004-0523

March 31, 2006

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1.0 Introduction

Haldimand County Hydro Inc. distributes electricity to 20,237 customers in Haldimand County. Our customer base is made up of a unique combination of rural and suburban customers stretching over 1252 square kilometers.

Our desire to promote a sustainable conservation culture with our customers facilitated our participation in a regional approach to program development to derive economies of scale but to also create consistent regional information to the customers across 11 LDC's, known as NEPPA (Niagara Erie Public Power Alliance).

The NEPPA group has long been known in the Industry as a leader in facilitating regional understanding of regulatory changes, public safety messaging, co-ordination of training and now conservation and demand management.

Our Conservation and Demand Management (CDM) plan was prepared as a NEPPA initiative. Together we represent 525,000 customers and a total of $5.5 million dollars of CDM funding. Our primary goal is to leverage common solutions and deliverables to maximize results when ever feasible.

During 2005, our primary concentration was to plan and create our foundation. High on the list was emphasizing customer communication branding in the form of Conserver Joe to begin changing and building awareness for the long term. In 2006 our customers will enjoy further localized programming as well as our support for programming designed and delivered by the OPA.

The following table shows the approved plan expenditures by project as well as actual expenditures to December 31, 2005.[1]

.

Project	Target Customers	Shared Initiative with NEPPA	Approved Expenditures	Actual Expenditure to Dec. 31, 2005
Co-branded Mass Market Program	Residential and <50 kW customers	Development of Conserver Family	60,000	$44,983.29[2]
Social Housing	Residential	Under Review	$20.000	$0
Smart Metering Low Volume	Residential	NEPPA and OUSM	$15,000	$5,989.51
Energy Audit >50kW	>50kW	Under Review	$5000.00	$1,061.00
Smart Metering >50kW	>50kW	Local to HCH	$37,500	$4,985.70
Distribution Assets – Voltage Conversion	All	Local to HCH	$294,585.00	$103,833.68
Administration	All	Local to HCH	$5,000.00	$2,458.24
Project and Budget Totals			**$437,085.00**	**$163,311.42**

[1] All programs completed or started in 2005 are detailed in Appendix B with accumulated results in Appendix A. Actual reported spending varies from our 4th quarter filing spending by $20,130.00 to account for final expenditures for Lighten Your Electricity Bill coupon event.

[2] Co-Branded expenditures as reported in fourth OEB Quarterly Filings was $24,831.91. We have opted to include additional expenditures that were spent in 2006 but accrued to 2005. First Quarter 2006 filings for OEB CDM reporting will reflect the new information.

2.0 Evaluation of the CDM Plan

The Haldimand County Hydro has implemented CDM projects that has effectively reduced 88kW in demand with annual savings of 243,054 kWh and total project savings over the lifespan of the technology of 2,786,841 kWh.

Appendix A depicts our overall CDM portfolio summarizing both programs with qualitative and quantitative results. Our overall TRC value is $149,612 with total spending of $173,260.00. We have opted to not project TRC calculations for projects not completed by December 31, 2005.

Some programs are not designed to have specific quantifiable energy savings but are nevertheless effective and important in our view. Examples of this second category of program include:

- Educational components like the "Conserver Family" information
- Active participation in the implementation study of smart meters for low volume customers in Ontario
- Staff development and education in CDM

Our overall plan shows a NPV based on the Total Resource Cost analysis of the individual programs of $149,612.00. 2005 expenditures totaled $163,311.42

3.0 Discussion of the Programs

Below is a brief summary of our specific CDM activities completed and/or started in 2005. Appendix B includes details on programs with TRC values listed below.

Completed Projects

Lighten Your Electricity Bill

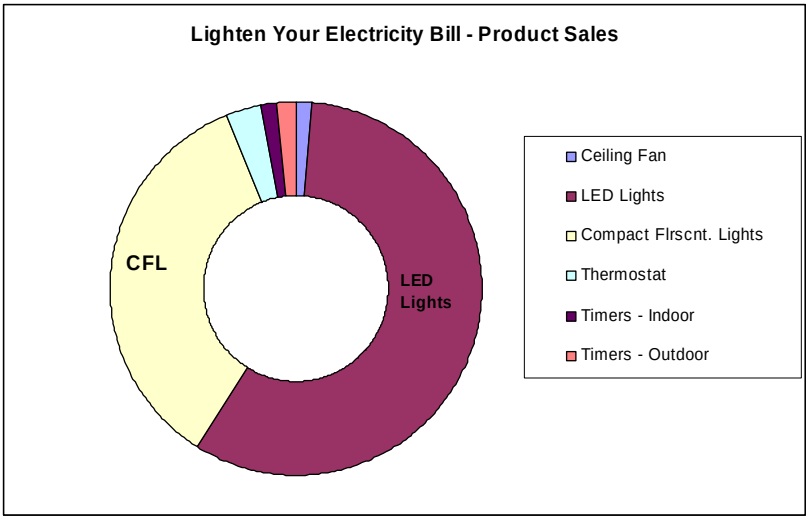
TRC - $149,612.00

Timeline – October 31, to December 31, 2005

In conjunction with other NEPPA members and LDC's across the province, we participated in a coupon campaign that offered customers the opportunity to purchase energy efficient products at Canadian Tire between October 1 to December 31, 2005.

All our residential customers received their Lighten Your Electricity Bill coupons via a special unaddressed package which also included a Conserver Joe Pamphlet and a coupon for Cold Water Wash Tide. In total 18,072 packages were mailed to both our

individually metered and bulk metered residential customers. The response was amazing. 25% of our customers took advantage of the coupons with a grand total of 4418 products purchased. The following chart depicts the product preferences of customers. Most popular were LED Christmas and Compact Fluorescents lights.



Ongoing Projects – Initiated in 2005

Cold Water Wash

TRC – to be provided with 2006 OEB Annual Report

Timeline – October 1, 2005 – March 31, 2006

In conjunction with other NEPPA members and LDCs across the province, Haldimand County Hydro supported and promoted the use of cold water to wash clothes. In partnership with Proctor and Gamble, we distributed 18,072 coupons.

We are expecting participation results in 2006 between 2-4%.

Voltage Conversion of Hagersville 4 kV to 27.6 kV

TRC - to be provided with 2006 OEB Annual Report

Timeline – August 2005 – August 2006

Permanent improvements to our overall loss factor will benefit all our customers. Haldimand County Hydro still has several areas that can and should be converted to a higher distribution voltage. In the community of Hagersville, an opportunity to change

sections of line from 4 kV to 27.6 kV was determined to provide overall benefits to our customer base. This conversion also provides us with the opportunity to take older (high loss) transformers out of service and replace them with more efficient transformers built to today's standards. In addition to the distribution transformers it allows us to take out of service a 4 kV substation operating with old high loss transformers.

The line conversion in Hagersville will be completed in two phases. The first phase of construction began in the last quarter of 2005. As of December 31, 2005 the new transformation was not yet ready to be energized. In 2006 it is anticipated that Phase I and Phase II will be completed.

Conserver Joe Media Kit

TRC - Qualitative

Timeline – May 2005- December 2006

In partnership with the NEPPA group, we developed a diversified customer education package referred to as our media kit. The media kit is built around Conserver Joe and his family. The development of the kit was designed around the concept of a family approach. Each family member brings their own special touch to encouraging and sharing conservation.

We know that changing our consumers' habits to sustain ongoing support and belief in conservation would take the resources of the working folks, as well as the push and enthusiasm of our youth. The media kit was developed with the knowledge that the product could be further expanded; including for example, an interactive youth website, school educational programs, updates on new technology and specific programming messaging.

To assist in local use of the Conserver Family, Product Use guidelines have been developed to keep our Conserver Family used in a consistent manner.

Conserver Joe and his family will be making appearances in various media as follows:

- ***Conservation Handbook*** – advises residential customers how to seasonally tune up their home to optimize energy use.
- ***Newsletter*** – a tabloid designed to share the success stories across LDCs utilizing Conserver Joe.
- ***Bill Inserts*** – Initially 10 bill inserts have been developed each sharing a single conservation message. All four family members share tips on saving energy.
- ***Website*** – www.conserverjoe.com – the website was developed to create a consistent message and branding. All NEPPA participants are able to use the website links.
- ***Print Ads*** – a selection of print ads have been developed for easy and quick circulation.

Haldimand County Hydro, in conjunction with five NEPPA members, embarked on a mass mailing of the Conservation Handbook in a specially marked unaddressed envelope to all residential households in Haldimand County, including any bulk metered customers. We leveraged our mass mailer to also include the Lighten Your Electricity Bill coupons and the Cold Water Wash coupon from Proctor and Gamble.

Training

TRC- Qualitative

Timeline – May 2005 – December 31, 2006

Haldimand County Hydro embarked on very limited training. Our training efforts were stemmed around understanding the application of the Total Resource Cost (TRC) calculations. Training included attendance at a generic seminar with Seeline and the purchase of a TRC Calculator tool from Enerspectrum.

Smart Metering – Low Volume Customers

TRC - Qualitative

Timeline – May 2005 – December 31, 2006

Haldimand County Hydro has elected not to directly facilitate a low volume smart metering pilot. However, we have embraced our responsibility to understand and participate in the development of smart metering implementation. We hold an active role on the OUSM working group in all facets and contribute to a more localized working group with the 11 NEPPA members to explore regional solutions.

All funding attributed to Smart Metering for low volume customers is to support our involvement in both these organizations.

Smart Metering – Large Volume Customers

TRC- To be Determined

Timeline – September 2005 – December 31, 2006

In response to the smart meter initiative all our large customers (>50 kW) who use greater than 200kW will have an interval meter installed. In total 13 customers will be receiving an interval meter. Changes to our Conditions of Service will ensure that all new construction with loading greater than 200 kW will automatically have an interval meter installed.

We also plan to communicate with all interval account customers to encourage monitoring and influence changes in their energy consumption and demand.

Administrative

TRC – Qualitative

Timeline – May 2005 – December 31, 2006

General administrative costs cover our participation in the Ontario Caucus Webinars, meeting expenses, and media costs for CDM plan notification. Administrative funds are not directly attributed to any one program, but rather are considered to be a general expense to cover our cost to participate.

4.0 Lessons Learned

Creating a balanced plan requires a concerted effort to include a mix of localized programming to engage a community commitment and broader initiatives to connect Haldimand County Hydro to a provincial goal and solution.

Our plan was developed with the express desire to improve our overall customer base efficiency and target specific customer segments. Our limited budget of $437,000 required some creative approaches.

The improvement of our overall loss factor by the conversion of 4 kV line in Hagersville to 27.6 kV benefits our entire customer base. Converting thirteen of our largest customers to interval meters is an important start to initiating other demand response

programs. Showing customers when they use the power, with the relative price signal, creates the proper support for ongoing efforts on their part that could lead to onsite capital improvements to reduce their consumption and demand.

Our participation in the Lighten Your Electricity Bill campaign was surprisingly successful and resulted in our ranking fifth in sales in the province. During our initial budgeting process we expected to see customer participation between a low of 3% and a high of 10%. Very early in the program we were tracking significantly higher customer participation. Final results - a whopping 25% customer participation.

A valued component of our CDM efforts is joint co-operation with the NEPPA members. It is clear that consistent messaging and branding over a larger geographical area supports the long term goal of a sustained conservation culture. In 2006 we are exploring the inclusion of other working groups to streamline messaging to customers, learn from each other and, whenever possible, co-ordinate programming to maximize customer results, share in costs and reduce confusion in the market.

Our greatest feat has been finding ways to stretch our programs to address needs of all our customers. We have explored minimal incremental cost initiatives to engage our community such as trade shows, school visits, and on-site visits with our large customers.

On the home front, we have turned our staff into “Kilowatt Busters” - daring them to find ways to reduce power on site, share their favourite tips, engage their families at home and generally become more aware of energy conservation. Our staff will always be our best ambassadors.

In 2006 we will continue to strive towards continued customer education to build on our past efforts and support of specific customer projects in lighting and social housing.

5.0 Conclusion

In 2005 we embarked on key initiatives to introduce our customers to our collective goals to commit to changing our energy usage. Our overall conclusion is that our customers are ready and very willing to participate in using new products and using energy differently. We were encouraged by a 25% participation response to the Lighten Your Electricity Bill campaign. Overall we rated 5th in the province in sales.

Haldimand County Hydro has benefited by actively participating with the NEPPA group to leverage programming, remaining adaptable to the regulatory changes, maintaining low cost initiatives through bulk purchasing and, whenever possible, fostering a regional solution for our customers. During the course of 2005, we have been able to maintain active participation with our current staff complement. Limited outside assistance has been contracted for TRC reporting purposes.

In 2006, we will be continuing to administer our plan with the start of new programs as well as the completion of programs initiated in 2005.

New in 2006

1. Low Income Program
2. LED Christmas Light Exchange
3. School Education

Ongoing from 2005

1. Cold Water Wash
2. Line Conversion in Hagersville
3. Smart Metering Customers >50kW General Service
4. Customer Education

We are committed to local delivery of CDM programming to our customers and look forward to continued cost effective innovative solutions.

Appendix A - Evaluation of the CDM Plan

Haldimand County Hydro Inc.

	Programming is Quantitative Results						Programming with Qualitative Results				
	Total	**Residential**	**< 50 GS**	**>50 GS**	**LDC System Hagersville Converions**	**Total Non TRC PROGRAMS**	**Administration and Training**	**Customer Education**	**Energy Audit >50 GS**	**Smart Metering Low Volume (Residential & < 50kW)**	**Other 4**
Net TRC value ($):	*$149,612*	$149,612				$0		$0			
Benefit to cost ratio:	*$7.26*	$7.26				$0		$0			
Number of participants or units delivered:	*4369*	4356		13		38149		18072		20077	
Total KWh to be saved over the lifecycle of the plan (kWh):	*2786841.5*	2786841.5				$0		$0			
Total in year kWh saved (kWh):	*243,054.77*	243,054.77				$0		$0			
Total peak demand saved (kW):	*88.00*	88.00				$0		$0			
Total kWh saved as a percentage of total kWh delivered (%):	*88.00*	0.0610%				$0		$0			
Peak kW saved as a percentage of LDC peak kW load (%):	*0.00*	0.0993%				$0		$0			
Gross in year C&DM expenditures ($):	*$163,311.42*	$26,677.10		$4,985.70	$103,833.68	$27,815	$4,600.01	$16,164.42	$1,061.00	$5,989.51	
Expenditures per KWh saved ($/kWh):*	*$0.0586*	$0.0096				$0		$0			
*Expenditures per KW saved ($/kW)**:*	*$1,856*	$303				$0		$0			

Utility discount rate (%):	8.56

HCH Energy Stats - 2005

2005 HCH Annual Energy Consumption	398288338 kWh
2005 Annual Peak Demand	88,622 kW

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix B - Discussion of the Program

(complete this section for each program)

A. **Name of the Program:**

Lighten Your Electricity Bill

Description of the program (including intent, design, delivery, partnerships and evaluation):
Include as much detail about the program.

Residential Coupon Program running from October 1st to December 31, 2005. Haldimand County Hydro partnered with Energyshop, Canadian Tire and 9 NEPPA members to deliver the a residential program that offered energy efficient products at a discounted rate. We joined 32 other LDC's across the province to launch a provincial campaign. Included discounts for the following products - ceiling fans, LED Lights, CFL, Programable Thermostats, Indoor and Outdoor Timers. . Our results have been extraordinary. We achieved a 25% participation from our customers. ***NOTE - Ceiling fans were not inlcuded in the calculations as no supporting data was available to quantify savings. Total dollars attributed to Ceiling fans have been included in total Utility Costs.***

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)	Measure4 (if applicable)
Base case technology:	Incandescent Xmas Lights	Incandescent - 60 watt	Non-programable Thermostat	No Timer
Efficient technology:	LED Lights	CFL- 15 watt	Programable Thermostats	In Door and Outdoor Timer
Number of participants or units delivered:	2545	1535	141	135
Measure life (years):	30	4	18	20

B. **TRC Results:**

		$	*173,508.73*
TRC Costs ($):			
	Utility program cost (less incentives):	*$*	*6,297.10*
	Participant cost:	$	17,600.00
	Total TRC costs:	$	23,897.10
Net TRC (in year CDN $):		$	149,611.63
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		$	7.26

C. **Results:** (one or more category may apply)

Conservation Programs:

Demand savings (kW):	*Summer*		9
	Winter		88
		lifecycle	*in year*
Energy saved (kWh):		*2786841.5*	243,054.77
Other resources saved :			
Natural Gas (m3):			
Other (specify):			

Demand Management Programs:

Controlled load (kW)	
Energy shifted On-peak to Mid-peak (kWh):	
Energy shifted On-peak to Off-peak (kWh):	
Energy shifted Mid-peak to Off-peak (kWh):	

Demand Response Programs:

Dispatchable load (kW):	
Peak hours dispatched in year (hours):	

Power Factor Correction Programs:

Amount of KVar installed (KVar):	
Distribution system power factor at begining of year (%):	
Distribution system power factor at end of year (%):	

Line Loss Reduction Programs:

Peak load savings (kW):		
	lifecycle	*in year*
Energy savngs (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):	
Energy generated (kWh):	
Peak energy generated (kWh):	
Fuel type:	

Other Programs (specify):

Metric (specify):	

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	$	-
	Incremental O&M:	$	6,297.10
	Incentive:	$	20,130.00
	Total:	$	26,427.10
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		
Participant costs ($):	*Incremental equipment:*		
	Incremental O&M:		
	Total:		

E. Comments:

LDC direct costs were determined based on the assumption that costs were shared as a percentage of overall sales. Incentive dollars are specific to coupon product.

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

APPENDIX G

2006 – OEB CDM Annual Report

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March 30, 2007

Delivered by Courier

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli
Board Secretary

Re: Haldimand County Hydro Inc.
RP-2004-0203 \ EB-2004-0523
Conservation and Demand Annual Report – 2006

Further to the Ontario Energy Board's (the "Board") orders approving electricity distributor conservation and demand ("CDM") plans, the Board requires that each distributor file an annual report including a cost benefit analysis.

Pursuant to the Board's "*Guideline for Annual Reporting of CDM Initiatives*" issued December 21, 2005 and the updated *"Requirements for Annual Reporting of CDM Initiatives"* issued March 1, 2007, please find enclosed three (3) hard copies and two (2) electronic copies of Haldimand County Hydro Inc.'s 2006 annual reporting which includes the following:

- 2006 Conservation and Demand Management Annual Report, dated March 30, 2007;
- Appendix A – Evaluation of the CDM Plan;
- Appendix B – Discussion of the Programs "Co-Branded Mass Market", "Smart Meter <50 kW", "Smart Meter >50 kW", "Energy Audit Feasibility Study", and "Distribution Conversion".
- Appendix C – Program and Portfolio Totals; as listed in Appendix B.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by S. Graham

Sherry Graham
Accounting Supervisor

2006 OEB Annual

Conservation and Demand Management Report

Submitted By Haldimand County Hydro Inc.

R. Jane Albert, Consumer Services Manager

RP-2004-0203/EB-2004-0523

March 30, 2007

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1.0 Introduction

Haldimand County Hydro Inc. distributes electricity to 20,237 customers in Haldimand County. Our customer base is made up of a unique combination of rural and suburban customers stretching over 1252 square kilometers.

Our desire to promote a sustainable conservation culture with our customers facilitated our participation in a regional approach to program development to derive economies of scale but to also create consistent regional information to the customers across 11 LDC's, known as NEPA (Niagara Erie Public Power Alliance).

The NEPA group has long been known in the Industry as a leader in facilitating regional understanding of regulatory changes, public safety messaging, co-ordination of training and now conservation and demand management.

Our Conservation and Demand Management (CDM) plan was prepared as a NEPA initiative. Together we represent 525,000 customers and a total of $5.5 million dollars of CDM funding. Our primary goal is to leverage common solutions and deliverables to maximize results when ever feasible.

During 2005 and 2006, our primary concentration was to plan and create our foundation. High on the list was emphasizing customer communication branding in the form of Conserver Joe to begin changing and building awareness for the long term. In 2007 our customers will enjoy further localized programming as well as our support for programming designed and delivered by the OPA.

The following table shows the approved plan expenditures by project as well as actual expenditures to December 31, 2006.[1]

Project	Target Customers	Shared Initiative with NEPA	Approved Budget	Actual Spent as of Dec. 31, 2005	Actual Spent as of Dec 31, 2006	Total Budget Spent
Co-branded Mass Market Program	Residential and <50 kW customers	Development of Conserver Family	60,000	$44,983.29[1]	$16,126.33[2]	$61,109.62
Social Housing	Residential	Under Review	$20,000.00	$0	0	
Smart Metering Low Volume	Residential	NEPA and OUSM	$15,000	$5,989.51	7613.72	$13,603.23
Energy Audit >50kW	>50kW	Under Review	$5,000.00	$1,061.00	4319.55	$5,380.55
Smart Metering >50kW	>50kW	Local to HCH	$37,500	$4,985.70	9928.55	$14,914.25
Distribution Assets – Voltage Conversion	All	Local to HCH	$294,585.00	$103,833.68	190751.32	$294,585.00
Administration			$5,000	$2,458.24	2937.64	$5,395.88
Project and Budget Totals			**$ 437,085.00**	**$ 118,328.13**	**$231,677.11**	**$ 394,988.53**

2.0 Evaluation of the CDM Plan

[1] All programs completed or started in 2005 are detailed in Appendix B with accumulated results in Appendix A. Actual reported spending varies from our 4th quarter filing spending by $20,130.00 to account for final expenditures for Lighten Your Electricity Bill coupon event.

[2] Expenditures of $726.30 are to applied in the final OEB Annual report in 2007.

The Haldimand County Hydro has implemented CDM projects that has effectively reduced 52kW in demand with annual savings of 490,714 kWh and total project savings over the lifespan of the technology of 3,431,582 kWh.

Appendix A depicts our overall CDM portfolio summarizing both programs with qualitative and quantitative results. Our overall TRC value is -$270,890.00 with total spending of $231,201. We have opted to not project TRC calculations for projects not completed by December 31, 2006.

Haldimand County Hydro is a strong advocate of actively participating with the OPA on their residential programs. In 2006 we participated in EKC promotions. We incurred no incremental costs during our participation. In this report we are not reporting on statistics of products purchased. It is our intention to continue promotion with staff and customers through our standard bill insert messages and local website which are presented to our customers.

Some programs are not designed to have specific quantifiable energy savings but are nevertheless effective and important in our view. Examples of this second category of program include:

- Educational components like the "Conserver Family" information
- Active participation in the implementation study of smart meters for low volume customers in Ontario

3.0 Discussion of the Programs

Below is a brief summary of our specific CDM activities started in 2005 and/or 2006 and completed in 2006. Appendix B includes details on programs with TRC values listed below as new this year, Appendix C that categorizes the programs and their attributes by customer.

Completed Projects

3.1 Voltage Conversion of Hagersville 4 kV to 27.6 kV

TRC - $(270,890.00)

Timeline – August 2005 to November 2006

The overall TRC analysis of the final project has indicated a negative net present value and would be considered a pilot CDM project. Haldimand County Hydro is committed to continued distribution improvements that will improve our reliability and efficient electricity distribution through our system.

Permanent improvements to our overall loss factor will benefit all our customers. Haldimand County Hydro still has several areas that will continue to be reviewed as part

of our capital project strategy. In the community of Hagersville, an opportunity to change sections of line from 4 kV to 27.6 kV was determined to provide overall long term benefit to our customer base. This conversion also provides us with the opportunity to take older (high loss) transformers out of service and replace them with more efficient transformers built to today's standards. In addition to the distribution transformers it allows us to take out of service a 4 kV substation operating with old high loss transformers.

3.2 LED Christmas Light Exchange

TRC - $52,183

Timeline – July 1, 2006 – December 31, 2006

In conjunction with our NEPA members, CLD group and Hydro One, Haldimand County Hydro supported and promoted the use of seasonal LED lights in Haldimand County. The three groups worked together to bulk purchase LED seasonal light strings. Our overall savings of 133,039 kWh equated to enough energy to power over 175 homes during the month of December.

Our program was planned to work with multiple levels of customer groups to promote a seasonal lighting alternative and to establish role models in our community by working with local community Christmas light committees.

All of our events were manned by volunteers from Haldimand County Hydro Staff and Board Members and their families. Our overall goal was to create the largest pile of old lights for grand finale. By all accounts we were very well received in the community.

Organized Events

1. LED Exchange Program with Haldimand County Residents

- Haldimand County Hydro attended two light up night venues offering a new multi-colour Christmas LED light string in exchange for two old incandescent light strings. A total of 1600 LED light sets were available for distribution

The following are some of the photo's taken at the two events

Caledonia Exchange

Dunnville Exchange

2. Conservation Bureau's "Every Kilowatt Counts" Coupon Campaign

• Residents across Ontario are invited to purchase energy efficient products from local merchants at discounted prices. LED Christmas lights discount coupons were made available from October 1st until November 30, 2006.

3. Monetary Exchange Program with Christmas Light Committees in Dunnville, Caledonia, Cayuga, Selkirk, Fisherville and Jarvis.

• Local Light-up Committees were invited to bring in their old Christmas lights in exchange for funding to help purchase new LED lights that provide greater durability on public displays and light standards along with significantly reducing electrical consumption. Our community light up committees have committed to a short term goal is transforming their community lighting displays to energy efficient standards. True leaders and advocates of energy efficiency. Overall energy saving since 2004-2005 season 21,958 kWh.

Christmas Lights Consumption (kWh)			
Community	**2004-2005**	**2005-2006**	**2006-2007**
Hagersville	3748	1764	647
Caledonia	9495	4483	32
Cayuga	6020	1655	2144
Dunnville	4047	4536	3585
Selkirk	1749	691	2
Jarvis	5681	1888	838
Caledonia (metered)			1534
Total	**30740**	**15017**	**8782**

Community Christmas Light Committee pictured in front of a sample of the lights they turned in for recycling.

4. LED Light Donation for Low Income Families

• HCH worked with four local food banks this year by contributing a string of LED light to Christmas food hampers for 418 families throughout Haldimand County. Although no incandescent lights are exchanged, the high efficiency of the LED lights can help them with energy costs and add to the enjoyment of the holidays.

LED Seasonal Light Finale

On December 8th, 2006, Haldimand County Hydro invited local media to cover the unveiling of all the incandescent lights that have been removed from Haldimand County due to the various programs administered during the past two months. On hand to celebrate the energy savings of the event were, Mayor Marie Trainer, Mr. Peter Love, Ontario's Chief Energy Conservation Officer, Haldimand County Hydro staff, representatives from NEPA Utilities, and some of the representatives of the local light committee's.

Pictured above are the incandescent lights collected and photo opportunity with the NEPA members, and Peter Love.

3.3 Cold Water Wash

TRC – $13,500.00

Timeline – October 1, 2005 – March 31, 2006

In conjunction with other NEPA members and LDCs across the province, Haldimand County Hydro supported and promoted the use of cold water to wash clothes. In partnership with Proctor and Gamble, we distributed 18,072 coupons with recorded customer coupon redemption of 3.3% or 601 customers.

Haldimand County Hydro does not presently bill for rental electric hot water heaters. Prior to the business being sold, we billed approximately 1300 water heaters ranging from 40 to 60 gallons.

Our primary delivery efforts included local organized staff promotions and customer contests to enhance awareness of the attributes and benefits of switching to cold water.

All customer received their “Switch to Cold” coupon via a direct mail in September. 2005. Results of the program were available March 2006.

Ongoing Projects – Initiated in 2005

3.4 Large User Energy Seminar and Audit Program

TRC- Qualitative and TRC value

Timeline – July 1, 2006 – March 31, 2006

The objective of the seminar and the audit program was to provide a better understanding of energy use for our largest users. We know from the Ontario Power Authorities Integrated Power Plan that our commercial and industrial customer provide the largest opportunity of peak demand reductions in the province. Haldimand County Hydro has a large and strong agricultural base and their presence was strong at the seminar.

Customers in attendance were offered the opportunity to receive up to $3000.00 towards an energy audit by a pre-approved contractor implemented energy changes. Funding was available for a maximum of 7 customers. As of December 31, 2006, a total 4 out of 7 audits have been complete. Further results will be reported in our final report.

3.5 Conserver Joe Website

TRC – Qualitative

Timeline – May 2005 to September 2007

In partnership with the NEPA group, we continue to maintain a diversified customer education package built around Conserver Joe and his family. The development of the design was built around the concept of a family approach to saving energy. Each family member brings their own special touch to encouraging and sharing conservation.

We know that changing our consumers' habits to sustain ongoing support and belief in conservation would take the resources of the working folks, as well as the push and enthusiasm of our youth.

To assist in local use of the Conserver Family, Product Use guidelines have been developed to keep our Conserver Family used in a consistent manner.

Conserver Joe and his family continues to make appearances in various media as follows:

- ***Conservation Handbook*** – advises residential customers how to seasonally tune up their home to optimize energy use.
- ***Newsletter*** – a tabloid designed to share the success stories across LDCs utilizing Conserver Joe.
- ***Bill Inserts*** – Initially 10 bill inserts have been developed each sharing a single conservation message. All four family members share tips on saving energy.
- ***Website*** – www.conserverjoe.com – the website was developed to create a consistent message and branding. All NEPPA participants are able to use the website links.
- ***Print Ads*** – a selection of print ads have been developed for easy and quick circulation.

3.6 Smart Metering – Low Volume Customers

TRC - Qualitative

Timeline –May, 2005 – September 2007

Haldimand County Hydro has elected not to directly facilitate a low volume smart metering pilot. However, we have embraced our responsibility to understand and participate in the development of smart metering implementation. We hold an active role on the OUSM working group in all facets and contribute to a more localized working group with the 11 NEPA members to explore regional solutions.

All funding attributed to Smart Metering for low volume customers is to support our involvement in both these organizations. In the last quarter of 2006, Haldimand County Hydro embarked on preparing our Smart Meter Implementation Plan which is projects full implementation by end of 2008 in the preliminary plans.

3.7 Smart Metering – Large Volume Customers

TRC - Qualitative

Timeline – May 2005 – September 2007

In response to the smart meter initiative all our large customers (>50 kW) who use gave greater than 200kW will have an interval meter installed. In total 13 customers have received an interval meter. Changes to our Conditions of Service will ensure that all new construction with loading greater than 200 kW will automatically have an interval meter installed.

Final equipment and communication equipment was installed in 2006. 2007 we will finalize our program by working with all interval customers to educate and entice energy conservation by reviewing hourly consumption data and patterns using web tools, OPA incentive programs. It is our intent to actively participate in the OPA LDC programs and communicate directly with this high volume customer base.

3.8 Administrative

TRC – Qualitative Timeline – January 1, 2006 – December 31, 2006

General administrative costs cover our participation in the general CDM meetings regarding program development, reporting and review. Administrative funds are not directly attributed to any one program, but rather are considered to be a general expense to cover our cost to participate.

4.0 Lessons Learned

Creating a balanced plan requires a concerted effort to include a mix of localized programming to engage a community commitment and broader initiatives to connect Haldimand County Hydro to a provincial goal and solution.

Our plan was developed with the express desire to improve our overall customer base efficiency and target specific customer segments. Our limited budget of $437,000 required some creative approaches.

The improvement of our overall loss factor by the conversion of 4 kV line in Hagersville to 27.6 kV benefits our entire customer base. It is clear that based on TRC alone, the line conversion does not present itself as a potential program. However, the added customer and system benefits of improved voltage continued to be a significant argument when continuing overall distribution system maintenance and improvements.

Never underestimate the power of a strong community program. Our signature program this year was our seasonal LED light exchange. We took extra effort to engage our whole community. First we engaged the enthusiasm of our Christmas community light leaders to change their lighting displays from incandescent to LED. We met with customers during light up nights to exchange lights, challenged our own staff to reduce their seasonal lighting energy use and we provided LED lights to low income families. We are planning to continue the program during the 2007 season.

Converting thirteen of our largest customers to interval meters is an important start to initiating other demand response programs. Showing customers when they use the power, with the relative price signal, creates the proper support for ongoing efforts on their part that could lead to onsite capital improvements to reduce their consumption and demand. We will be investigating adding more interval meters to our largest customers to use as a tool to promote a provincial energy awareness. Seeing will be believing.

A valued component of our CDM efforts is joint co-operation with the NEPA members. It is clear that consistent messaging and branding over a larger geographical area supports the long term goal of a sustained conservation culture. Our NEPA members continue to be a source of positive energy in maintaining the ongoing development of CDM in the

province. We believe we are able to promote and deliver more cost effective programs than by operating on our own.

On the home front, we have continued to engage our very own "Kilowatt Busters". Each staff member received home energy kits. We were pleased to work with Union Energy to spread the message of responsible energy use. Our staff continues to be our best ambassadors.

In 2007 we will continue to strive towards continued customer education.

5.0 Conclusion

2006 we focused on the engagement of our community. Extra effort was made to explore awareness. We looked to zero incremental cost measures such and the Mayor's Blackout challenge, radio appearances, CDM messages on all bill inserts and staff awareness.

We are expecting to finalize the balance of our budget of $42,489.37 by September 2007. Our primary focus will be our preparation to participate with the OPA on the four standard program offers that are due to commence June 15, 2007

Haldimand County Hydro has benefited by actively participating with the NEPA group to leverage programming, remaining adaptable to the regulatory changes, maintaining low cost initiatives through bulk purchasing and, whenever possible, fostering a regional solution for our customers. During the course of 2006, we have been able to maintain active participation with our current staff complement. Limited outside assistance has been contracted for TRC reporting purposes.

New in 2007

1. Low Income Program

Ongoing from 2005

1. Large User Energy Audit – ends March 31, 2007
2. Smart Metering Customers >50kW General Service
3. Customer Education
4. LED Christmas Light Exchange

We are committed to local delivery of CDM programming to our customers and look forward to continued cost effective innovative solutions in conjunction with the OPA.

Appendix A - Evaluation of the CDM Plan

Highlighted boxes are to be completed manually, white boxes are linked to Appendix C and will be brought forward automatically.

	[5] Cumulative Totals Life-to-date	Total for 2006	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	[4] Smart Meters	Other #1	Other #2
Net TRC value ($):	**-$ 226,990**	**-$ 272,768**	**$ 65,683**	**$ (4,320)**	**$ -**	**$ -**	**$ -**	**$ (331,193)**		**$ -**	**$ -**
Benefit to cost ratio:	$ 0.36	0.36	7.95	0.00	0.00	0.00	0.00	0.19		0.00	0.00
Number of participants or units delivered:	6370	2001	2000					1			
Lifecycle (kWh) Savings:	6,218,424	3,431,582	1,918,197	0	0	0	0	1,513,385		0	0
Report Year Total kWh saved (kWh):	733,769	490,714	427,657	0	0	0	0	63,058		0	0
Total peak demand saved (kW):	140	52	37	0	0	0	0	14		0	0
*Total kWh saved as a percentage of total kWh delivered (%):***	*0.193%*	*0.129%*	*0.113%*	*0.000%*	*0.000%*	*0.000%*	*0.000%*	*0.017%*	*0.000%*	*0.000%*	*0.000%*
Peak kW saved as a percentage of LDC peak kW load (%):		0.061%	0.044%	0.000%	0.000%	0.000%	0.000%	0.017%	0.000%	0.000%	0.000%
[1] *Report Year Gross C&DM expenditures ($):*	*$ 394,512*	$ 231,201	$ 15,650	$ 4,320	$ -	$ -	$ -	$ 190,751	$ 17,542	$ -	$ -
[2] *Expenditures per KWh saved ($/kWh):*	*$ 0.13*	$ 0.07	$ 0.01	$ -	$ -	$ -	$ -	$ 0.13		$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	*$ 6,329.03*	$ 4,473.03	$ 419.30	$ -	$ -	$ -	$ -	$ 13,280.44		$ -	$ -

Utility discount rate (%):	7.52

[1] Expenditures are reported on accrual basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
[5] Includes total for the reporting year, plus prior year, if any (for example, 2006 CDM Annual report for third tranche will include 2005 and 2004 numbers, if any.

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Co-Branded Mass Market

Description of the program (including intent, design, delivery, partnerships and evaluation):

2006 Program included:
community Light Exchange Program - exchange incandescent lights for LED lights.
Conserver Joe Website - Annual Hosting Fees.
Water Wash.

LED Light

Switch to Cold

Measure(s):

	5 Watt	Mini Watt	Switch to Cold
Base case technology:	5 WATT Christmas lights C-7(64 lights)	Incandescent Mini Lights	Average existing stock
Efficient technology:	LED Christmas Lights (indoor or outdoor)	LED Christmas Lights (indoor or outdoor)	Cold Water Washing (Detergent)
Number of participants or units delivered for reporting year:	1000	1000	601
Measure life (years):	30	30	1
Number of Participants or units delivered life to date	2273	2273	601

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 75,140	$ 248,648
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	-$ 1,150	-$ 43,833
Incremental Measure Costs (Equipment Costs)	-$ 8,308	-$ 25,908
Total TRC costs:	-$ 9,458	-$ 69,741
Net TRC (in year CDN $):	$ 65,683	$ 178,907
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	7.95	3.57

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	13	22
	Winter	37	125

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	1,918,197	427,657	4,705,038	670,712
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)			
Energy shifted On-peak to Mid-peak (kWh):			
Energy shifted On-peak to Off-peak (kWh):			
Energy shifted Mid-peak to Off-peak (kWh):			

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):		
	lifecycle	*in year*
Energy savings (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 1,150	$ 45,883
	Incentive:	$ 14,500	$ 34,630
	Total:	$ 15,650	$ 80,513
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

All TRC analysis completed using OEB published Assumptions/Measures List.
Total 2006 TRC costs include expenditures for Conserver Joe Website and Cold Water Wash programs.
Cumulative TRC results include 2005 results for Lighten your Electricity Bill program.
2005 Customer Education program and staff training costs are included in total cummulative Life to Date Actual Program Costs

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Smart Meter <50 kW

Description of the program (including intent, design, delivery, partnerships and evaluation):

Smart Meter Study Program

Measure(s):

	Measure 1 (if applicable)	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:		
Net TRC (in year CDN $):		
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*			
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 7,614	$ 13,603
	Incremental O&M:		
	Incentive:		
	Total:	$ 7,614	$ 13,603
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Smart Meter >50 kW

Description of the program (including intent, design, delivery, partnerships and evaluation):

Install and implement interval meters with all customer > 200 kW

Measure(s):

	Measure 1 (if applicable)	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:		
Net TRC (in year CDN $):		
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*			
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 9,929	$ 14,914
	Incremental O&M:		
	Incentive:		
	Total:	$ 9,929	$ 14,914
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Energy Audit Feasibility Study

Description of the program (including intent, design, delivery, partnerships and evaluation):

Breakfast Seminar with Customers > 250,000 annual kWh

Measure(s):

	Measure 1 (if applicable)	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	-$ 4,320	-$ 5,381
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:	-$ 4,320	-$ 5,381
Net TRC (in year CDN $):	-$ 4,320	-$ 5,381
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	-	-

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

		lifecycle	*in year*	*Cumulative Lifecycle* / Cumulative Annual Savings
Demand savings (kW):	*Summer*			
	Winter			
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 4,320	$ 5,381
	Incentive:		$ -
	Total:	$ 4,320	$ 5,381
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

TRC benefits to be determined in 2007 and will be included in the final CDM report.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Distribution Conversion

Description of the program (including intent, design, delivery, partnerships and evaluation):

Hagersville line voltage conversion from 4 kV to 27.6 kV

Measure(s):

	27.6 kV Conversion	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	4.16 kV System		
Efficient technology:	27.6 kV System		
Number of participants or units delivered for reporting year:	1		
Measure life (years):	25		
Number of Participants or units delivered life to date	0		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	*$ 75,616*	$ 75,616
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	-$ *406,810*	-$ 510,644
Incremental Measure Costs (Equipment Costs)	$ -	$ -
Total TRC costs:	-$ 406,810	-$ 510,644
Net TRC (in year CDN $):	-$ 331,193	-$ 435,027
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ 0.19	$ 0.15

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*			
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):		14	14
	lifecycle	*in year*	
Energy savings (kWh):	1,513,385	63,058	63,058

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 190,751	$ 294,585
	Incremental O&M:		
	Incentive:		
	Total:	$ 190,751	$ 294,585
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

No TRC reported in 2005 since conversion work was not complete.
Total TRC costs include non 3rd tranche funding of 216,059.
Total Cummulative Life to Date expenditures of $295,585 represents total 3rd tranche funding.
Since the voltage conversion was completed in 2 phases, 2006 TRC results included avoided energy and peak benefits as well as 2006 TRC costs only; 2005 expenditures were included in Cummulative Life to Date TRC costs.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix C - Program and Portfolio Totals

Report Year: **2006**

1. Residential Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved ***	Report Year Gross C&DM Expenditures ($)
Co-Branded Mass Market	$ 75,140	$ 9,458	$ 65,683	7.95	427,657	1,918,197	37	$ 15,650
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Residential**	$ 75,140	$ 9,458	$ 65,683	7.95	427,657	1,918,197	37	$ 15,650
Residential Indirect Costs not attributable to any specific program →								
Total Residential TRC Costs		$ 9,458						
****Totals TRC - Residential**	**$ 75,140**	**$ 9,458**	**$ 65,683**	**7.95**				

2. Commercial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Energy Audit Feasibility Study		$ 4,320	-$ 4,320	0.00				$ 4,320
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Commercial**	$ -	$ 4,320	-$ 4,320	0.00	0	0	0	$ 4,320

Commercial Indirect Costs not attributable to any specific program →				
Total TRC Costs		$ 4,320		
****Totals TRC - Commercial**	**$ -**	**$ 4,320**	**-$ 4,320**	**0.00**

3. Institutional Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Institutional**	$ -	$ -	$ -	0.00	0	0	0	$ -
Institutional Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Institutional**	**$ -**	**$ -**	**$ -**	**0.00**				

4. Industrial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				

Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Industrial**	$ -	$ -	$ -	0.00	0	0	0	$ -
Industrial Indirect Costs not attributable to any specific program	→							
Total TRC Costs		$ -						
****Totals TRC - Industrial**	**$ -**	**$ -**	**$ -**	**0.00**				

5. Agricultural Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Agricultural**	$ -	$ -	$ -	0.00	0	0	0	$ -
Agricultural Indirect Costs not attributable to any specific program	→							
Total TRC Costs		$ -						
****Totals TRC - Agricultural**	**$ -**	**$ -**	**$ -**	**0.00**				

6. LDC System Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Distribution Conversion	$ 75,616	$ 406,810	-$ 331,193	0.19	63,058	1,513,385	14	$ 190,751
Name of Program B			$ -	0.00				

Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program C			$ -	0.00				
***Totals App. B - LDC System**	$ 75,616	$ 406,810	-$ 331,193	0.19	63,058	1,513,385	14	$ 190,751
LDC System Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ 406,810						
****Totals TRC - LDC System**	**$ 75,616**	**$ 406,810**	**-$ 331,193**	**0.19**				

7. Smart Meters Program

Only spending information that was authorized under the 3rd tranche of MARR is required to be reported for Smart Meters.

Report Year Gross C&DM Expenditures ($) →	17,542

8. Other #1 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #1**	$ -	$ -	$ -	0.00	0	0	0	$ -
Other #1 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Other #1**	**$ -**	**$ -**	**$ -**	**0.00**				

9. Other #2 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #2**	$ -	$ -	$ -	0.00	0	0	0	$ -
Other #2 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Other #2**	**$ -**	**$ -**	**$ -**	**0.00**				

LDC's CDM PORTFOLIO TOTALS

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
***TOTALS FOR ALL APPENDIX B**	$ 150,756	$ 420,587	-$ 269,830	0.36	$ 490,714	$ 3,431,582	$ 52	$ 231,201
*Any **other** Indirect Costs not attributable to any specific program* →		$ 2,938						
TOTAL ALL LDC COSTS		$ 423,524						
****LDC' PORTFOLIO TRC**	$ 150,756	$ 423,524	-$ 272,768	0.36				

* The savings and spending information from this row is to be carried forward to Appendix A.
** The TRC information from this row is to be carried forward to Appendix A.
***Peak demand displayed represents winter peak demand

APPENDIX H

2007 – OEB CDM Annual Report

98 Archibald Road, RR2, Kettleby, Ontario, L0G 1J0
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Web: www.enerspectrum.com

1 Greendale Drive, Caledonia, ON, N3W 2J3 Tel: (905) 765-5211 Fax: (905) 765-5316

March 31, 2008

Delivered by Courier

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli
Board Secretary

Re: Haldimand County Hydro Inc.
RP-2004-0203 \ EB-2004-0523
Conservation and Demand Annual Report – 2007
Third Tranche Funding

Further to the Ontario Energy Board's (the "Board") orders approving electricity distributor conservation and demand ("CDM") plans, the Board requires that each distributor file an annual report including a cost benefit analysis.

Haldimand County Hydro Inc.'s submission is pursuant to the Board's "*Guideline for Annual Reporting of CDM Initiatives*" issued December 21, 2005 and the updated *"Requirements for Annual Reporting of CDM Initiatives"* issued March 1, 2007. Current reporting requirements have remained the same as per the Board's letter dated March 3, 2008.

Please find enclosed three (3) hard copies which include the following:

- 2007 Annual Report – CDM Third Tranche Funding, dated March 31, 2008;
- Appendix A – Evaluation of the CDM Plan;
- Appendix B – Discussion of the Programs "Co-Branded Mass Market and Social Housing", "Smart Meter <50 kW", "Smart Meter >50 kW", "Energy Audit Feasibility Study", and "Distribution Conversion".
- Appendix C – Program and Portfolio Totals; as listed in Appendix B.

Also enclosed are electronic copies (CD) which include:

1. "2007 Annual Report,CDM Third Tranche Funding_Haldimand_20080331" (SINGLE PDF DOCUMENT - ALL MATERIALS) (*PDF*)
2. "2007 Annual Report,CDM Third Tranche Funding_Haldimand_20080331" (APPENDICES A, B AND C, AS NOTED ABOVE) (*EXCEL*)

These electronic files have also been forwarded to your attention, by email to Boardsec@oeb.gov.on.ca, today.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by J.A. Scott

Jacqueline A. Scott
Finance Manager

2007 OEB Annual

Conservation and Demand Management Report

Submitted By Haldimand County Hydro Inc.

R. Jane Albert, Consumer Services Manager

RP-2004-0203/EB-2004-0523

March 31, 2008

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1.0 Introduction

Haldimand County Hydro Inc. distributes electricity to 20,237 customers in Haldimand County. Our customer base is made up of a unique combination of rural and suburban customers stretching over 1252 square kilometers.

Our desire to promote a sustainable conservation culture with our customers facilitated our participation in a regional approach to program development to derive economies of scale but to also create consistent regional information to the customers across 11 LDC's, known as NEPA (Niagara Erie Public Power Alliance).

The NEPA group has long been known in the industry as a leader in facilitating regional understanding of regulatory changes, public safety messaging, co-ordination of training and now conservation and demand management.

Our Conservation and Demand Management (CDM) plan was prepared as a NEPA initiative. Together we represent 525,000 Ontario electric customers and a total of $5.5 million dollars of CDM funding. Our primary goal is to leverage common solutions and deliverables to maximize results when ever feasible.

During 2005 and 2006, and finally in 2007our primary concentration was to plan and create our foundation. High on the list was emphasizing customer communication branding in the form of Conserver Joe to begin changing and building awareness for the long term and well as engaging both our community and staff in thinking conservation on a daily basis.

Our budget for 2007 was based on $41, 846.50 from the balance of our third tranche funding with an additional $16,829.02 reported on projects that exceeded budget. Furthermore, our regulatory asset account as reported to the OEB will reflect a total of $453,762.52.

Further community based Conservation programs were facilitated through our normal budget process and through our ongoing participation with the OPA standard programs.

Reallocation of Third Tranche Funding

Reallocation of Third Tranche Funding

Progarm	Approved Budget	Final Expenditures	Deviation
Co-branded Mass Market Program	60,000	$68,204.38	$ 8,204.38
Social Housing	$20,000.00	$7,469.28	$ 12,530.72
Smart Metering Low Volume	$15,000	$13,810.77	$ 1,189.23
Energy Audit >50kW	$5,000.00	$9,968.19	$ 4,968.19
Smart Metering >50kW	$37,500	$33,514.26	$ 3,985.74
Distribution Assets – Voltage Conversion	$294,585.00	$298,570.74	$3,985.74
Administration	$5,000	$22,224.90	$17,224.90
Total \Third Tranche Budget	437,085	$ 453,762.52	$ 52,088.90
Budget Portion Over Third Tranche MARR			$ 16,677.52
Maximum Value of Funds to be Re -allocated within 20% of total Approved Budget (20% of $437,085)			$ 87,417.00

During the course of the three year implementation, $52,088.90 was re-allocated between programs. $3,985.74 represented a capital re-allocation from the Smart Meter >50kW to the Distribution Asset-Voltage Conversion. $48,103.16 represents the expenditure re-allocation between non-capital projects.

The Regulatory Asset quarterly reporting component to the OEB for account “1565” will reflect the capital re-allocation of $3,985.74 which represents final capital dollars spent and allocated to Third Tranche funding.

2.0 Evaluation of the CDM Plan

Haldimand County Hydro has implemented CDM projects that have effectively reduced a cumulative total of 173kW in demand with annual savings of 877,698 kWh and total project savings over the lifespan of the technology of 8,629,533 kWh.

Appendix A depicts our overall CDM portfolio summarizing both programs with qualitative and quantitative results. Our overall TRC value is negative $94,412 with total spending of $453,493. We have opted to not project TRC calculations for projects that are deemed qualitative but recognize and strongly support the need for such programs that instill the long-term message of conservation to our customers.

Haldimand County Hydro is a strong advocate of actively participating with the OPA on their residential programs. In 2007 we participated in EKC promotions as well as the OPA standard programs commencing June 2007. In this report we are not reporting on statistics of products purchased. It is our intention to continue promoting with staff and customers through our standard bill insert messages and local website which are presented to our customers.

Some programs are not designed to have specific quantifiable energy savings but are nevertheless effective and important in our view. Examples of this second category of programs include:

- Educational components like the “Conserver Family” information
- Active participation in the implementation study of smart meters for low volume customers in Ontario
- Energy Audits and industry information sessions.

3.0 Discussion of the Programs

Below is a brief summary of our specific CDM activities completed in 2007.

3.1 LED Christmas Light Exchange

TRC - $10,600
Timeline – July 1, 2007 – September 30, 2007

In conjunction with our NEPA members, Haldimand County Hydro supported and promoted the use of seasonal LED lights in Haldimand County. Our overall annual savings of 16,345 with product lifecycle savings of 484,406 kWh.

Our program was planned to work with multiple levels of customer groups to promote a seasonal lighting alternative. Our key events where as follows:

- Customer Light Up Night
- Community Christmas Light Committees
- Local Parade

Organized Events

1. LED Exchange Program with Haldimand County Residents

A customer light exchange was co-ordinated with the Cayuga Christmas Light Up night. We noticed a significant trend in 2007. In 2007 we hosted one light exchange. Customer numbers dropped significantly. We had many customers just drop by to tell us that all their Christmas lights have been changed. Over 600 sets of old lights were collected and disposed of through a recycling program.

4. Caledonia Parade

Haldimand County Hydro volunteers participated in the Caledonia Christmas parade. Our theme – Conservation. Accompanied by our mascot, Conserver Abby, we handed out 200 sets of LED lights and promoted our Light Exchange in Cayuga.

3.3 Low Income Kits – Lighten Your Load

TRC – $131,600

Timeline – April, 2007 – July 15, 2007

Haldimand County Hydro provided 350 conservation kits for low income families in our community. The kits contained the following:

- 4 – 15 watt compact fluorescents
- Conserver Joe Booklet and general information
- Notepad/check list

We utilized our local food banks to ensure kits properly distributed to those in need.

3.4 Large User Energy Seminar and Audit Program

TRC - Qualitative

Timeline – July 1, 2006 – March 2007

The objective of the seminar and the audit program was to provide a better understanding of energy use for our largest users. We know from the Ontario Power Authorities Integrated Power Plan that our commercial and industrial customers provide the largest opportunity of peak demand reductions in the province. Haldimand County Hydro has a large and strong agricultural base and their presence was strong at the seminar.

Customers in attendance were offered the opportunity to receive up to $3000.00 towards an energy audit by a pre-approved contractor and implemented energy changes. Funding was available for a maximum of 7 customers. As of December 31, 2006, a total 4 out of 7 audits have been complete. Customer's had until March 31, 2007 to complete their audit. Final results, 6 customers completed an audit however no notification was received of any implemented conservation projects.

3.5 Conserver Joe Website

TRC – Qualitative

Timeline – May 2005 to September 30, 2007

In partnership with the NEPA group, we continue to maintain a diversified customer education package built around Conserver Joe and his family. The development of the design was built around the concept of a family approach to saving energy. Each family member brings their own special touch to encouraging and sharing conservation.

We know that changing our consumers' habits to sustain ongoing support and belief in conservation would take the resources of the working folks, as well as the push and enthusiasm of our youth.

To assist in local use of the Conserver Family, Product Use guidelines have been developed to keep our Conserver Family used in a consistent manner.

Conserver Joe and his family continue to make appearances in various media as follows:

- ***Conservation Handbook*** – advises residential customers how to seasonally tune up their home to optimize energy use.
- ***Newsletter*** – a tabloid designed to share the success stories across LDCs utilizing Conserver Joe.
- ***Bill Inserts*** – Initially 10 bill inserts have been developed each sharing a single conservation message. All four family members share tips on saving energy.
- ***Website*** – www.conserverjoe.com – the website was developed to create a consistent message and branding. All NEPPA participants are able to use the website links.
- ***Print Ads*** – a selection of print ads have been developed for easy and quick circulation.

3.6 Smart Metering – Low Volume Customers

TRC - Qualitative

Timeline – May, 2005 – September 30, 2007

Haldimand County Hydro has elected not to directly facilitate a low volume smart metering pilot. However, we have embraced our responsibility to understand and

participate in the development of smart metering implementation. We hold an active role on the OUSM working group in all facets and contribute to a more localized working group with the 11 NEPA members to explore regional solutions.

All funding attributed to Smart Metering for low volume customers is to support our involvement in both these organizations. Haldimand County Hydro is preparing our implementation for 2009.

3.7 Smart Metering – Large Volume Customers

TRC - Qualitative

Timeline – May 2005 – September 30, 2007

In 2007 a further 10 customers received an interval meter. In total 23 customers received an interval meter with this program. These customers use a monthly average demand of greater than 150kW. In November, a meeting was held with all large use customers with a key focus on how to use their interval meter to aid in energy reductions. During the meeting customers were made aware of the OPA business incentives program. Changes to our Conditions of Service will ensure that all new construction with loading greater than 200 kW will automatically have an interval meter installed.

3.8 Administrative

TRC – Qualitative

Timeline – January 1, 2006 – September 30, 2008

For the preparation and review of our Distribution Conversion program, a consulting firm was utilized to prepare the engineering analysis of the final project. Their involvement included initial review of the project as well and the final TRC calculation.

4.0 Lessons Learned

Creating a balanced plan requires a concerted effort to include a mix of localized programming to engage a community commitment and broader initiatives to connect Haldimand County Hydro to a provincial goal and solution.

Our plan was developed with the express desire to improve our overall customer base efficiency and target specific customer segments. Our limited budget of $437,000 required some creative approaches.

Never underestimate the power of a strong community program. Our signature program this year was our second annual seasonal LED light exchange. We took extra effort to engage our whole community. First we engaged the enthusiasm of our Christmas community light leaders to change their lighting displays from incandescent to LED. We met with customers during light up night to exchange lights, challenged our own staff to reduce their seasonal lighting energy use and we provided LED lights to customer in our local Christmas parade.

In 2006 we converted our 13 largest customers that were currently without an interval meter. In 2007 we were able to install an additional 9 interval meters whose annual peak demand is greater than 150 kW. Converting our largest customers to interval meters is an important start to initiating other demand response programs. Showing customers when they use power with the relative price signal, creates the proper support for ongoing efforts on their part that could lead to onsite capital improvements to reduce their consumption and demand.

A valued component of our CDM efforts is joint co-operation with the NEPA members. It is clear that consistent messaging and branding over a larger geographical area supports the long term goal of a sustained conservation culture. Our NEPA members continue to be a source of positive energy in maintaining the ongoing development of CDM in the province. We believe we are able to promote and deliver more cost effective programs than by operating on our own.

5.0 Conclusion

2007 we continued our focus on the engagement of our community. Extra effort was made to explore awareness. We looked to zero incremental cost measures such as press releases, CDM messages on all bill inserts and staff awareness.

Haldimand County Hydro has benefited by actively participating with the NEPA group to leverage programming, remaining adaptable to the regulatory changes, maintaining low cost initiatives through bulk purchasing and, whenever possible, fostering a regional solution for our customers. During the course of 2007, we have been able to maintain active participation with our current staff complement.

New in 2007

1. Low Income Program – *Lighten Your Load*
2. LED Seasonal Light Promotions – second annual
3. Additional Interval Meters Installed
4. Energy Seminar

We are committed to local delivery of CDM programming to our customers and look forward to continued cost effective innovative solutions in conjunction with the OPA.

Appendix A - Evaluation of the CDM Plan

Highlighted boxes are to be completed manually, white boxes are linked to Appendix C and will be brought forward automatically.

	[5] Cumulative Totals Life-to-date	Total for 2007	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	[4] Smart Meters	Other #1	Other #2
Net TRC value ($):	**-$ 94,412**	**$ 132,578**	**$ 132,578**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**
Benefit to cost ratio:	$ 15.14	14.78	14.78	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Number of participants or units delivered:	7371	1001	1000					1			
Lifecycle (kWh) Savings:	8,629,533	2,411,109	897,724	0	0	0	0	1,513,385		0	0
Report Year Total kWh saved (kWh):	877,698	143,929	143,929	0	0	0	0	0		0	0
Total peak demand saved (kW):	173	33	33	0	0	0	0	0		0	0
*Total kWh saved as a percentage of total kWh delivered (%):***	*0.226%*	*0.038%*	*0.038%*	*0.000%*	*0.000%*	*0.000%*	*0.000%*	*0.000%*	*0.000%*	*0.000%*	*0.000%*
Peak kW saved as a percentage of LDC peak kW load (%):	*0.001967385*	0.039%	0.039%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
[1] *Report Year Gross C&DM expenditures ($):*	*$ 453,969*	$ 59,457	$ 14,521	$ 4,588	$ -	$ -	$ -	$ 3,986	$ 18,808	$ -	$ -
[2] *Expenditures per KWh saved ($/kWh):*	*$ 0.08*	$ 0.02	$ 0.02	$ -	$ -	$ -	$ -	$ 0.00		$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	*$ 3,657.73*	$ 1,801.73	$ 440.02	$ -	$ -	$ -	$ -	$ -		$ -	$ -

Utility discount rate (%):	7.52

[1] Expenditures are reported on accrual basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
[5] Includes total for the reporting year, plus prior year, if any (for example, 2006 CDM Annual report for third tranche will include 2005 and 2004 numbers, if any.
** Correction was made to 2005 Appendix A as input to cummulative Totals Life-to-date

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Co-Branded Mass Market and Social Housing

Description of the program (including intent, design, delivery, partnerships and evaluation):

2007 Program included:
community Light Exchange Program - exchange incandescent lights for LED lights.
Conserver Joe Website - Annual Hosting Fees (2006 and 2007).
Your Load - Low Income Kits

LED Light

Lighten

Measure(s):

	5 Watt	Mini Watt	Lighten Your Load Kits
Base case technology:	5 WATT Christmas lights C-7(64 lights)	Incandescent Mini Lights	Average existing stock
Efficient technology:	LED Christmas Lights (indoor or outdoor)	LED Christmas Lights (indoor or outdoor)	1400 CFL (4 15w lights per kit)
Number of participants or units delivered for reporting year:	500	500	350
Measure life (years):	30	30	1
Number of Participants or units delivered life to date	500	500	350

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	*$ 142,200*	$ 390,848.00
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	*-$ 5,202*	-$ 40,931.22
Incremental Measure Costs (Equipment Costs)	-$ 4,420	-$ 30,328.00
Total TRC costs:	-$ 9,622	-$ 71,259.22
Net TRC (in year CDN $):	$ 132,578	$ 319,588.78
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	14.78	5.48

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0	22
	Winter	33	158

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	897,724	143929	5,602,762	518,528
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 4,951	$ 50,834
	Incentive:	$ 9,362	$ 43,992
	Total:	$ 14,313	$ 94,826
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

All TRC analysis completed using OEB published Assumptions/Measures List.
Total 2007 TRC costs include expenditures for Conserver Joe Website .
Cumulative TRC results include 2006 results . 2007 Conserver Joe Website
Maintenance Fees
2005 Customer Education program and staff training costs are included in total cummulative Life to Date Actual Program Costs

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Smart Meter <50 kW

Description of the program (including intent, design, delivery, partnerships and evaluation):

Smart Meter Study Program

Measure(s):

	Measure 1 (if applicable)	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:		
Net TRC (in year CDN $):		
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*			
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 207.54	$ 13,810.77
	Incremental O&M:		
	Incentive:		
	Total:	$ 207.54	$ 13,810.77
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Smart Meter >50 kW

Description of the program (including intent, design, delivery, partnerships and evaluation):

Install and implement interval meters with all customer > 150kW

Measure(s):

	Measure 1 (if applicable)	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:		
Net TRC (in year CDN $):		
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*			
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 18,600.01	$ 33,514.26
	Incremental O&M:		
	Incentive:		
	Total:	$ 18,600.01	$ 33,514.26
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Energy Audit Feasibility Study

Description of the program (including intent, design, delivery, partnerships and evaluation):

Energy Audit sponsor program. Six Haldimand County Hydro customer completed their audit.

Measure(s):

	Measure 1 (if applicable)	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		-$ 1,061
Incremental Measure Costs (Equipment Costs)		
Total TRC costs:		-$ 1,061
Net TRC (in year CDN $):		-$ 1,061
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	#DIV/0!	-

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*		
	Winter		

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

	lifecycle	in year	
Peak load savings (kW):			
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:		$ 4,319.55
	Incentive:	$ 4,587.64	$ 4,587.64
	Total:	$ 4,587.64	$ 8,907.19
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

In total 7 customers applied for and 6 completed their energy audit. As of December 31, 2007 - none of the 6 customers have indicated completion of any of the initiatives. NO TRC is being reported.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix B - Discussion of the Program

(complete this Appendix for each program)

A. **Name of the Program:** Distribution Conversion

Description of the program (including intent, design, delivery, partnerships and evaluation):

Hagersville line voltage conversion from 4 kV to 27.6 kV. 2007 reflects an adjustment to third tranche reported capital of $3985.74. This

Measure(s):

	27.6 kV Conversion	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	4.16 kV System		
Efficient technology:	27.6 kV System		
Number of participants or units delivered for reporting year:	1		
Measure life (years):	25		
Number of Participants or units delivered life to date	0		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		$ 75,616.26
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		-$ 510,643.53
Incremental Measure Costs (Equipment Costs)	$ -	$ -
Total TRC costs:	$ -	-$ 510,643.53
Net TRC (in year CDN $):	$ -	-$ 435,027.27
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	#DIV/0!	$ 0.15

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*			
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):				
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			14
	lifecycle	*in year*	
Energy savings (kWh):	1,513,385		63,058

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 3,985.74	$ 298,570.74
	Incremental O&M:		
	Incentive:		
	Total:	$ 3,985.74	$ 298,570.74
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

No TRC reported in 2005 since conversion work was not complete.
Total TRC costs include non 3rd tranche funding of 216,059.
Total Cummulative Life to Date expenditures of $295,585 represents total 3rd tranche funding.
Since the voltage conversion was completed in 2 phases, 2006 TRC results included avoided energy and peak benefits as well as 2006 TRC costs only; 2005 expenditures were included in Cummulative Life to Date TRC costs.
2007 a Capital cost adjustments of $3985.74 was included to reflect the adjustment made at the 2007 year end. No change in TRC required as the total project cost was used to determine TRC.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit b

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made

Appendix C - Program and Portfolio Totals

Report Year: **2006**

1. Residential Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved ***	Report Year Gross C&DM Expenditures ($)
Co-Branded Mass Market and Social	$ 142,200	$ 9,622	$ 132,578	14.78	143,929	897,724	33	$ 14,313
Smart Meter <50kw			$ -	0.00				$ 208
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Residential**	$ 142,200	$ 9,622	$ 132,578	14.78	143,929	897,724	33	$ 14,521
Residential Indirect Costs not attributable to any specific program →								
Total Residential TRC Costs		$ 9,622						
****Totals TRC - Residential**	**$ 142,200**	**$ 9,622**	**$ 132,578**	**14.78**				

2. Commercial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Energy Audit Feasibility Study		$ -	$ -	0.00				$ 4,588
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Commercial**	$ -	$ -	$ -	0.00	0	0	0	$ 4,588

Commercial Indirect Costs not attributable to any specific program →				
Total TRC Costs		$ -		
****Totals TRC - Commercial**	**$ -**	**$ -**	**$ -**	**0.00**

3. Institutional Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Institutional**	$ -	$ -	$ -	0.00	0	0	0	$ -
Institutional Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Institutional**	**$ -**	**$ -**	**$ -**	**0.00**				

4. Industrial Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				

Name of Program J			$ -	0.00				
***Totals App. B - Industrial**	$ -	$ -	$ -	0.00	0	0	0	$ -
Industrial Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Industrial**	**$ -**	**$ -**	**$ -**	**0.00**				

5. Agricultural Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Agricultural**	$ -	$ -	$ -	0.00	0	0	0	$ -
Agricultural Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Agricultural**	**$ -**	**$ -**	**$ -**	**0.00**				

6. LDC System Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Distribution Conversion	$ -	$ -	$ -	0.00	0	1,513,385	0	$ 3,986
Name of Program B			$ -	0.00				

Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program C			$ -	0.00				
***Totals App. B - LDC System**	$ -	$ -	$ -	0.00	0	1,513,385	0	$ 3,986
LDC System Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - LDC System**	**$ -**	**$ -**	**$ -**	**0.00**				

7. Smart Meters Program

Only spending information that was authorized under the 3rd tranche of MARR is required to be reported for Smart Meters.

Report Year Gross C&DM Expenditures ($) →	18,808

8. Other #1 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program F			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #1**	$ -	$ -	$ -	0.00	0	0	0	$ -
Other #1 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Other #1**	**$ -**	**$ -**	**$ -**	**0.00**				

9. Other #2 Programs

List each Appendix B in the cells below; Insert additional rows as required.

Note: To ensure the integrity of the formulas, please insert the additional rows in the middle of the list below.

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
Name of Program A			$ -	0.00				
Name of Program B			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program D			$ -	0.00				
Name of Program E			$ -	0.00				
Name of Program C			$ -	0.00				
Name of Program G			$ -	0.00				
Name of Program H			$ -	0.00				
Name of Program I			$ -	0.00				
Name of Program J			$ -	0.00				
***Totals App. B - Other #2**	$ -	$ -	$ -	0.00	0	0	0	$ -
Other #2 Indirect Costs not attributable to any specific program →								
Total TRC Costs		$ -						
****Totals TRC - Other #2**	**$ -**	**$ -**	**$ -**	**0.00**				

LDC's CDM PORTFOLIO TOTALS

	TRC Benefits (PV)	TRC Costs (PV)	$ Net TRC Benefits	Benefit/Cost Ratio	Report Year Total kWh Saved	Lifecycle (kWh) Savings	Total Peak Demand (kW) Saved	Report Year Gross C&DM Expenditures ($)
***TOTALS FOR ALL APPENDIX B**	$ 142,200	$ 9,622	$ 132,578	14.78	$ 143,929	$ 2,411,109	$ 33	$ 59,457
*Any **other** Indirect Costs not attributable to any specific program* →		$ 17,555.32	Mass Market General Expenses (726.30) incurred in 2005… $16829.02					
TOTAL ALL LDC COSTS		$ 27,177						
****LDC' PORTFOLIO TRC**	$ 142,200	$ 27,177	$ 115,023	5.23				

* The savings and spending information from this row is to be carried forward to Appendix A.
** The TRC information from this row is to be carried forward to Appendix A.
***Peak demand displayed represents winter peak demand

APPENDIX I

2008 – OEB CDM Annual Report

98 Archibald Road, RR2, Kettleby, Ontario, L0G 1J0
Phone: 905.939.8239 Fax: 905.939.4606
Web: www.enerspectrum.com

1 Greendale Drive, Caledonia, ON, N3W 2J3 Tel: (905) 765-5211 Fax: (905) 765-5316

May 14, 2009

Delivered by Courier

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli
Board Secretary

Re: Haldimand County Hydro Inc. (Licence # ED-2002-0539)
2008 Annual Reporting of Conservation and Demand Management Initiatives – Third Tranche Funding (RP-2004-0203)

Further to orders issued by the Ontario Energy Board (the "Board") in proceeding RP-2004-0203 approving electricity distributor conservation and demand management ("CDM") plans, and in accordance with the Board's letter dated February 2, 2009 in this regard, the Board requires that each distributor file an annual report regarding its CDM initiatives, including a cost benefit analysis – regardless of the level of CDM activity undertaken in 2008 through the third tranche funding initiative.

Accordingly, please now find enclosed three (3) hard copies which include the following:

- 2008 Annual Report – Total Life Evaluation of Third Tranche CDM Funding, dated April 28, 2009;
- Appendix A – Evaluation of the CDM Plan for each year – 2005, 2006, and 2007; and
- Appendix D – Total Life Evaluation of the CDM Plan.

Also enclosed are electronic copies included on a disk (CD) which include:

1. "2008 Annual Report_CDM Third Tranche Funding_Haldimand_20090514" (SINGLE PDF DOCUMENT - ALL MATERIALS) (*PDF*)
2. "2008 Annual Report_CDM Third Tranche Funding_Haldimand_20090514" (APPENDICES A AND D, AS NOTED ABOVE) (*EXCEL*)

These electronic files have also been forwarded to your attention, by email to Boardsec@oeb.gov.on.ca, today.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by J.A. Scott

Jacqueline A. Scott
Finance Manager

Total Life Evaluation of the Third Tranche CDM Plan

Submitted By:
Haldimand County Hydro
RP-2004-0203/EB-2004-0523
May 14, 2009

May 14, 2009

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Suite 2700
Toronto, ON M4P lE4

Attention: Kirsten Walli
Board Secretary

Total Life Evaluation of the Third Tranche CDM Plan
RP-2004-0203/EB-2004-0523

Dear Ms. Walli:

Haldimand County Hydro Inc. learned much from its Third Tranche CDM program experience between 2005 and 2007. While there are challenges in serving more than 20,000 customers across a rural and suburban area of 1,252 square kilometres, a regional approach to programming with our Niagara Erie Power Alliance (NEPA) partners drove economies of scale and delivered consistent messages to customers.

This approach proved successful within the Residential customer segment, returning a net TRC value of almost $350,000 over the duration of Third Tranche CDM expenditures. Expenditures on distribution system improvements will return more than 3 million kWh in energy savings over its lifecycle, and greater than 60,000 kWh over three years.

Overall, 2005, 2006, and 2007 CDM activities enabled the creation of a CDM foundation within our customer base. Awareness of Haldimand County Hydro as an energy efficiency partner was imprinted across all classes of customers, while important branding was executed with respect to the Conserver Joe family to engage both current and future electricity customers in conservation values.

As the accompanying Appendix D - Total Life Evaluation of the CDM Plan details, Haldimand County Hydro expended $453,969.42 on its Third Tranche CDM activities between 2005 and September, 2007. A strong Cumulative Net TRC value of $347,873 was achieved in the

residential segment over the Third Tranche period, but this was offset by a negative Cumulative Net TRC value of -$331,193 from distribution system improvements (voltage conversion) which have a lengthy payback period, but will save more than 3 million kWh over its lifecycle. Overall, Third Tranche CDM expenditures achieved a Cumulative Net TRC value of -$8133 between 2005 and 2007.

Lessons Learned

The success achieved between 2005 and 2007 in the residential segment was the result of several factors, including public awareness, the engagement of younger electricity users, and the community as a whole. This was particularly evident in such initiatives as the Conserver Joe website, and in seasonal LED light exchanges in conjunction with a community parade and other events. Community leaders also helped motivate a wider shift in consumer behaviour by changing seasonal light displays to LED from incandescent.

The success in the residential sector also taught us that CDM results are not dependent on expenditures. Through zero incremental cost measures such as press releases, CDM messages on bill inserts and staff awareness efforts; much was accomplished in terms of awareness and the CDM program readiness of stakeholders.

Industrial customers benefited from Third Tranche CDM programming with the conversion of Haldimand County Hydro's 22 largest customers to interval meters in 2006 and 2007. Though the near-term benefits of meter conversion in terms of net TRC is nominal or even negative, this initiative is the platform for introducing future demand response programs for customers whose demand is greater than 150 kW. It underscores the learning that there is tremendous long-term value in enabling future programming, that in turn, can spur customer investments to reduce consumption and demand.

Perhaps the most important lesson that the Third Tranche CDM program afforded to Haldimand County Hydro is that collaboration provides significant operational leverage. In co-operation with our NEPA partners, we planned and executed CDM programming. It was the basis for consistent messaging and branding over a substantive geographical area, and

initiated the shift to a conservation culture. This alliance is also helping member LDCs realize more efficient purchasing of CDM materials and support services.

Overall, Haldimand County Hydro views its Third Tranche CDM experience as an optimal training ground. It created a capability and readiness to bring added value to customers, while alerting the community to the potential of conservation. It also put in place the relationships with other LDCs, suppliers and stakeholders that is critical to our CDM success.

We are now applying our new expertise and relationships to implement CDM programs sponsored by the Ontario Power Authority, with the confidence that much more can be accomplished in our CDM mission.

Please call if you have any questions or wish to discuss any aspect of this submission.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Jane Albert
Consumer Services Manager

Appendix A - Evaluation of the CDM Plan

Highlighted boxes are to be completed manually, white boxes are linked to Appendix C and will be brought forward automatically.

	Total for 2005	Residential	[5] Low Income	Commercial	>50 GS	Industrial	Agricultural	LDC System	[4] Smart Meters	Total Non TRC Program Cost	Other #2
Net TRC value ($):	**$ 149,612**	**$ 149,612**	**$**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**	**$ -**
Benefit to cost ratio:		7.26		0.00	0.00	0.00	0.00	0.00		0.00	0.00
Number of participants or units delivered:	*4,369*	4,356			13						
Lifecycle (kWh) Savings:	2,786,842	2,786,842		0	0	0	0	0		0	0
Report Year Total kWh saved (kWh):	243,055	243,055		0	0	0	0	0		0	0
Total peak demand saved (kW):	88	88		0	0	0	0	0		0	0
Total kWh saved as a percentage of total kWh delivered (%):	0.0070	0.0070									
Peak kW saved as a percentage of LDC peak kW load (%):	0.0010	0.0010									
[1] *Report Year Gross C&DM expenditures ($):*	163,311	$ 26,677	$		$ 4,986			$ 103,834		$ 27,815	
[2] *Expenditures per KWh saved ($/kWh):*	$ 0.06	$ 0.01	$	$ -	$ -	$ -	$ -	$ -		$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	$ 1,855.81	$ 303.15	$	$ -	$ -	$ -	$ -	$ -		$ -	$ -

Utility discount rate (%):	8.56	Total kWh delivered	398,288,338	Indirect Cost	$ -
		Total kW delivered	88,622		

[1] Expenditures are reported on accrual basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
[5] Includes totals from Low Income programs that fall under both commercial and residential.

Appendix A - Evaluation of the CDM Plan

Highlighted boxes are to be completed manually, white boxes are linked to Appendix C and will be brought forward automatically.

	Total for 2006	Residential	[5] Low Income	Commercial	Institutional	Industrial	Agricultural	LDC System	[4] Smart Meters	Other #1	Other #2
Net TRC value ($):	**-$ 272,768**	**$ 65,683**	**$**	**$ (4,320)**				**$ (331,193)**			
Benefit to cost ratio:	0.36	7.95						0.19			
Number of participants or units delivered:	*2,001*	2,000						1			
Lifecycle (kWh) Savings:	3,431,582	1,918,197						1,513,385			
Report Year Total kWh saved (kWh):	490,715	427,657						63,058			
Total peak demand saved (kW):	51	37						14			
Total kWh saved as a percentage of total kWh delivered (%):	0.130%	0.113%						0.400%			
Peak kW saved as a percentage of LDC peak kW load (%):	0.061%	0.044%						0.017%			
[1] *Report Year Gross C&DM expenditures ($):*	231,201	$ 15,650	$	$ 4,320				$ 190,751	$ 17,542		
[2] *Expenditures per KWh saved ($/kWh):*	$ 0.07	$ 0.01	$	$ -	$ -	$ -	$ -	$ 0.13		$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	$ 4,533	$ 422.97	$	$ -	$ -	$ -	$ -	$ 13,625.07		$ -	$ -

Utility discount rate (%):	7.52	Total kWh delivered	378,457,522	Indirect Cost:	$ 2,938
		Total kW delivered	84,091		

[1] Expenditures are reported on accrual basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
[5] Includes totals from Low Income programs that fall under both commercial and residential.

Appendix A - Evaluation of the CDM Plan

Highlighted boxes are to be completed manually, white boxes are linked to Appendix C and will be brought forward automatically.

	Total for 2007	Residential	[5] Low Income	Commercial	Institutional	Industrial	Agricultural	LDC System	[4] Smart Meters	Other #1	Other #2
Net TRC value ($):	**$ 132,578**	**$ 132,578**	**$**					**$ -**			
Benefit to cost ratio:	14.78	14.78						0.19			
Number of participants or units delivered:	*1,001*	1,000						1			
Lifecycle (kWh) Savings:	2,411,109	897,724						1,513,385			
Report Year Total kWh saved (kWh):	143,929	143,929									
Total peak demand saved (kW):	33	33									
Total kWh saved as a percentage of total kWh delivered (%):	0.038%	0.038%						0.000%			
Peak kW saved as a percentage of LDC peak kW load (%):	0.039%	0.039%						0.000%			
[1] *Report Year Gross C&DM expenditures ($):*	$ 59,457	$ 14,521	$	$ 4,588				$ 3,986	$ 18,808		
[2] *Expenditures per KWh saved ($/kWh):*	$ 0.02	$ 0.02	$	$ -	$ -	$ -	$ -	$ 0		$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	$ 1,802	$ 440	$	$ -	$ -	$ -	$ -	$ -		$ -	$ -

Utility discount rate (%):	7.52	Total kWh delivered	378,760,526	Indirect Cost	$ 17,555
		Total kW delivered	84,615		

[1] Expenditures are reported on accrual basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
[5] Includes totals from Low Income programs that fall under both commercial and residential.

Appendix D - Total Life Evaluation of the CDM Plan

Table is to be completed manually by totalling the information from each year of activity

	[5] Cumulative Totals Life-to-date	Residential	[6] Low Income	Commercial	>50 GS	Industrial	Agricultural	LDC System	[4] Smart Meters	Total Non TRC Program Cost	Other
Net TRC value ($):	**-$ 8,133**	**$ 347,873**	**$ -**	**-$ 4,320**	**$ -**	**$ -**	**$ -**	**-$ 331,193**	**$ -**	**$ -**	
Benefit to cost ratio:	***1.04***	9.10	-	-	-	-	-	0.19	-	-	-
Number of participants or units delivered:	***7,371***	7,356	-	-	13	-	-	2	-	-	-
Lifecycle (kWh) Savings:	***8,629,533***	5,602,763	-	-	-	-	-	3,026,770	-	**-**	-
Total kWh saved (kWh):	***877,699***	814,641	-	-	-	-	-	63,058	-	0.00	-
Total peak demand saved (kW):	***172***	158	-	-	-	-	-	14	-	-	-
Total kWh saved as a percentage of total kWh delivered (%):	***0.076%***	0.071%	0.000%	0.000%	0.000%	0.000%	0.000%	0.005%	0.000%	0.000%	0.000%
Peak kW saved as a percentage of LDC peak kW load (%):	***0.194%***	0.178%	0.000%	0.000%	0.000%	0.000%	0.000%	0.016%	0.000%	0.000%	0.000%
[1] *Gross C&DM expenditures ($):*	**$ 453,969.42**	$ 56,848.10	$ -	$ 8,908.00	$ 4,985.70	$ -	$ -	$ 298,570.68	$ 36,350.00	27,815	$ -
[2] *Expenditures per KWh saved ($/kWh):*	**$ 0.52**	$ 0.01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[3] *Expenditures per KW saved ($/kW):*	**$ 2,639.36**	$ 359.80	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utility discount rate (%):		Total kWh delivered	1,155,506,386	Indirect Cost	$ 20,493						
		Total kW delivered	88,622								

[1] Expenditures are reported on cumulative basis.
[2] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
[3] Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
[4] Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Actual expenditures for the total third tranche period need to be reported.
[5] Includes total for the reporting year, plus prior years, if any (for example, 2008 CDM Annual report for third tranche will include 2007, 2006, 2005 and 2004 numbers, if any).
[6] Includes totals from Low Income programs that fall under both commercial and residential.