EXHIBIT 1
ADMINISTRATIVE DOCUMENTS

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 Whitby Hydro Electric Corporation 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 Whitby Hydro Electric Corporation for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2010.
Applicant's Name:	Whitby Hydro Electric Corporation
Applicant's Address for Service:	100 Taunton Road East Whitby, Ontario L1N 5R8
	Attention: Ramona Abi-Rashed, Treasurer
	Telephone: (905) 668-5878 Fax: (905) 668-9379 E-mail: rabirashed@whitbyhydro.on.ca

ADMINISTRATION

APPLICATION

1. Introduction

(a) The Applicant is Whitby Hydro Electric Corp. (referred to in this Application as the "Applicant" or "Whitby Hydro"). The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Whitby. The Applicant carries on the business of distributing electricity within the Town of Whitby.

(b) Whitby Hydro 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 identified as part of this Exhibit.

(c) Except where specifically identified in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution dated May 27, 2009 (the "Filing Requirements") in order to prepare this application.

2. Proposed Distribution Rates and Other Charges

(a) The Proposed Tariff of Rates and Charges proposed in this Application is identified in Exhibit 1 and Exhibit 8 (Table 8-15) and the material being filed in support of this Application sets out Whitby Hydro'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 or the implementation of any other mitigation measures;

(iv.) the other service charges proposed by the Applicant are the same as those previously approved by the OEB except for one new charge for legal letters;

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

5. Relief Sought

Whitby Hydro hereby applies for an Order or Orders approving the proposed distribution rates and other charges set out in the Proposed Tariff of Rates and Charges identified in this Exhibit, as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2010.

Whitby Hydro requests that the existing rates be made interim commencing May 1, 2010 in the event that there is insufficient time for the applicant to prepare a draft rate order and the Board to issue a final Decision and Order in this application for the implementation of the proposed rates and charges as of May 1, 2010.

Whitby Hydro acknowledges that the preparation of this application was delayed, but expects that the extra effort taken to ensure that the evidence appropriately addresses the Board's revised filing requirements dated May 27, 2009 will help to expedite the review process. In addition, the filing delay provided an opportunity for Whitby Hydro to incorporate the most recently approved budget updates for major projects such as the 407 extension and Highway 7 widening which have a significant impact on the assets, resources and related calculations for rate-setting.

To assist the Board, Whitby Hydro is committed to working closely and cooperatively with Board Staff and any intervening parties to ensure that the pre-hearing processes proceed expeditiously and effectively so that any outstanding issues can be dealt with by way of written submissions.

6. Form of Hearing Requested

Whitby Hydro respectfully requests that this application be decided by way of a written hearing. As noted in the previous section, Whitby Hydro believes that the evidence filed in this application is complete and accurately supports the relief being sought, but if concerns do arise the company plans to work with Board staff and other parties to clarify the record and provide additional information as required in a timely fashion in order to expedite the hearing process and facilitate written submissions.

DATED at Whitby, Ontario, this January 15, 2010

All of which is respectfully submitted,
WHITBY HYDRO ELECTRIC CORPORATION

Original signed by

Mrs. Ramona Abi-Rashed,
Treasurer

WHITBY HYDRO ELECTRIC CORPORATION

PROPOSED TARIFF OF RATES AND CHARGES

EFFECTIVE MAY 1, 2010

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.62
Smart Meter Funding Adder	$	2.13
Distribution Volumetric Rate Rider	$/kWh	0.0148
Regulatory Asset Recovery Rate Rider	$/kWh	(0.0017)
LRAM Rate Rider	$/kWh	0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051
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	$	20.44
Smart Meter Funding Adder	$	2.13
Distribution Volumetric Rate	$/kWh	0.0200
Regulatory Asset Recovery Rate Rider	$/kWh	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
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	$	191.34
Smart Meter Funding Adder	$	2.13
Distribution Volumetric Rate	$/kW	4.0566
Regulatory Asset Recovery Rate Rider	$/kW	(0.6875)
LRAM Rate Rider	$/kW	0.0153
Retail Transmission Rate – Network Service Rate	$/kW	2.0448
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7770
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)	$	9.59
Distribution Volumetric Rate	$/kWh	0.0312
Regulatory Asset Recovery Rate Rider	$/kWh	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
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 light)	$	4.19
Distribution Volumetric Rate	$/kW	11.3413
Regulatory Asset Recovery Rate Rider	$/kW	(0.4912)
Retail Transmission Rate – Network Service Rate	$/kW	1.5499
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4026
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 light)	$	1.40
Distribution Volumetric Rate	$/kW	5.6149
Regulatory Asset Recovery Rate Rider	$/kW	(0.7408)
Retail Transmission Rate – Network Service Rate	$/kW	1.5420
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3738
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration:		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post-dated cheques	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge / change of occupancy charge	$	30.00
Returned Cheque charge (plus bank charges)	$	15.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Legal letter charge	$	15.00

Non-Payment of Account:		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00

Install / remove load control device – during regular hours	$	65.00
Install / remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
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

Retailer Service Agreement -- One time charge to establish the service agreement	$	100.00
Monthly Fixed Charge (per retailer)	$	20.00
Monthly Variable Charge (per customer, per retailer)	$/cust	0.50
Distributor-Consolidated Billing -monthly charge (per customer, per retailer)	$/cust	0.30
Retailer-Consolidated Billing -monthly credit (per customer, per retailer)	$/cust	(0.30)
Service Transaction Request -request fee (per request, applied to the requesting party)	$	0.25
Service Transaction Request -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

TLF - Secondary Metered Customer <5,000 kW	1.0454
TLF - Primary Metered Customer <5,000 kW	1.0349

CONTACT INFORMATION

WHITBY HYDRO ELECTRIC CORPORATION
100 Taunton Road East
Whitby, Ontario L1N 5R8

TREASURER:

Mrs. Ramona Abi-Rashed
Telephone: 905- 668-5878
Facsimile: 905- 668-9379
E-mail: rabirashed@whitbyhydro.on.ca

REGULATORY FINANCIAL MANAGER:

Mrs. Susan Reffle
Telephone: 905- 668-5878
Facsimile: 905- 668-9379
E-mail: sreffle@whitbyhydro.on.ca

VICE PRESIDENT:

Mr. John Sanderson
Telephone: 905- 668-5878
Facsimile: 905- 668-9379
E-mail: jsanderson@whitbyhydro.on.ca

SPECIFIC APPROVALS REQUESTED

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

- Approval to charge rates effective May 1, 2010 to recover a service revenue requirement of $20,747,189, based on a cost of service rate application, as set out in Exhibit 1 (Table 1-1).

- 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%, as set out in Exhibit 5 consistent with 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 of 1.0454 as set out in Exhibit 8.

- Approval of the Applicant's proposed change to the Retail Transmission-Network Service and Retail Transmission-Connection charges as set out in Exhibit 8 based on the OEB's Guideline G-2008-0001 – Electricity distribution Retail Transmission Service Rates, issued July 22, 2009

- Approval of the proposed Smart Meter Adder as set out in Exhibit 9 based on the OEB's Guideline G-2008-0037 – Smart Meter Funding and Cost Recovery, issued October 2, 2008.

- Approval of the proposed Lost Revenue Adjustment Mechanism (LRAM) rate rider as set out in Exhibit 10. This rate rider is proposed for a two year recovery period and follows the OEB Report EB-2007-0037 – Guidelines for Electricity Distributor Conservation and Demand Management.

- Approval to dispose of the following Deferral and Variance Account Balances as at December 31, 2008 (including interest to April 30, 2010) in the form of a Regulatory Asset Recovery Rate Rider over a four-year period using the method of recovery described in Exhibit 9.

  1518 – Retail Cost Variance Account – Retail
  1525 – Miscellaneous Deferred Debits
  1548 – Retail Cost Variance Account – STR
  1550 – LV Variance Account
  1580 – RSVA – Wholesale Market Service Charge
  1584 – RSVA – Retail Transmission Network Charge
  1586 – RSVA – Retail Transmission Connection Charge
  1588 – RSVA – Power
  1588 – RSVA – Power (sub-account Global Adjustment)

1590 – Recovery of Regulatory Asset Balance

- Approval of the Wholesale Market and Rural Rate Protection Charges, Standard Supply Service – Administrative Charge, Transformer Ownership Allowance and Primary Metering Allowance which are unchanged from the currently approved Rate Order.

- Approval of proposed Specific Service Charges as set out in Exhibit 3. These charges remain unchanged from those currently approved with the exception of one additional charge for Legal Letters. All charges are consistent with the standard rates developed and issued by the OEB as part of the 2006 EDR process.

- Approval of Retail Service Charges which are unchanged from the currently approved Rate Order.

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 would be of interest to the Board, its staff and any other parties intervening in this Application:

- The amount of Whitby Hydro’s proposed Revenue Requirement;
- The reasonableness of the 2010 Capital Program;
- The reasonableness of the 2010 Operating, Maintenance and Administrative Budget;
- The reasonableness of the 2010 Weather Normalized Forecast;
- The reasonableness of the proposed Electricity Distribution Rates;
- The reasonableness of the proposed Lost Revenue Adjustment Mechanism;
- The reasonableness of the proposed Smart Meter Rate Funding Adder;
- The reasonableness of the proposed Regulatory Asset Recoveries;
- The reasonableness of the proposed Rate Design.

Whitby Hydro has provided detailed evidence covering all of these areas and is prepared to submit any additional information that other parties may require to complete the record in a cost effective manner either by interrogatory responses or technical conference so that the application can be decided efficiently by way of a written hearing.

PROCEDURAL ORDERS/MOTIONS/NOTICES

On March 12, 2007, the OEB issued a Report titled "LDC Screening Methodology to Establish a Rebasing Schedule for Electricity LDCs". The purpose of that 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 that Report provided an opportunity for LDCs to "self-nominate" to be rebased in a particular year.

On January 30, 2008, the OEB issued its Final Selection of Electricity Distributors for Rate Rebasing in 2009 and 2010 (Board File No. EB-2006-0330). Whitby Hydro was listed in Appendix A and was scheduled to rebase in 2009. Subsequently the Board issued a letter dated May 27, 2008 asking Whitby Hydro (along with other distributors scheduled to rebase in 2009) to consider deferring their cost of service application to 2010. The Board indicated that they would welcome deferral requests given its interest in reducing work loads. On June 20, 2008, Whitby Hydro advised the Board that they were able to accommodate their request. This change was confirmed in the Board’s letter dated March 5, 2009 whereby Whitby Hydro was identified in

Appendix A as an Electricity Distributor scheduled for Rate Rebasing in 2010 (Board File No. EB-2009-0028).

No further Procedural Orders of directions have been issued by the OEB to the date of filing this application.

ACCOUNTING ORDERS REQUESTED

Whitby Hydro is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

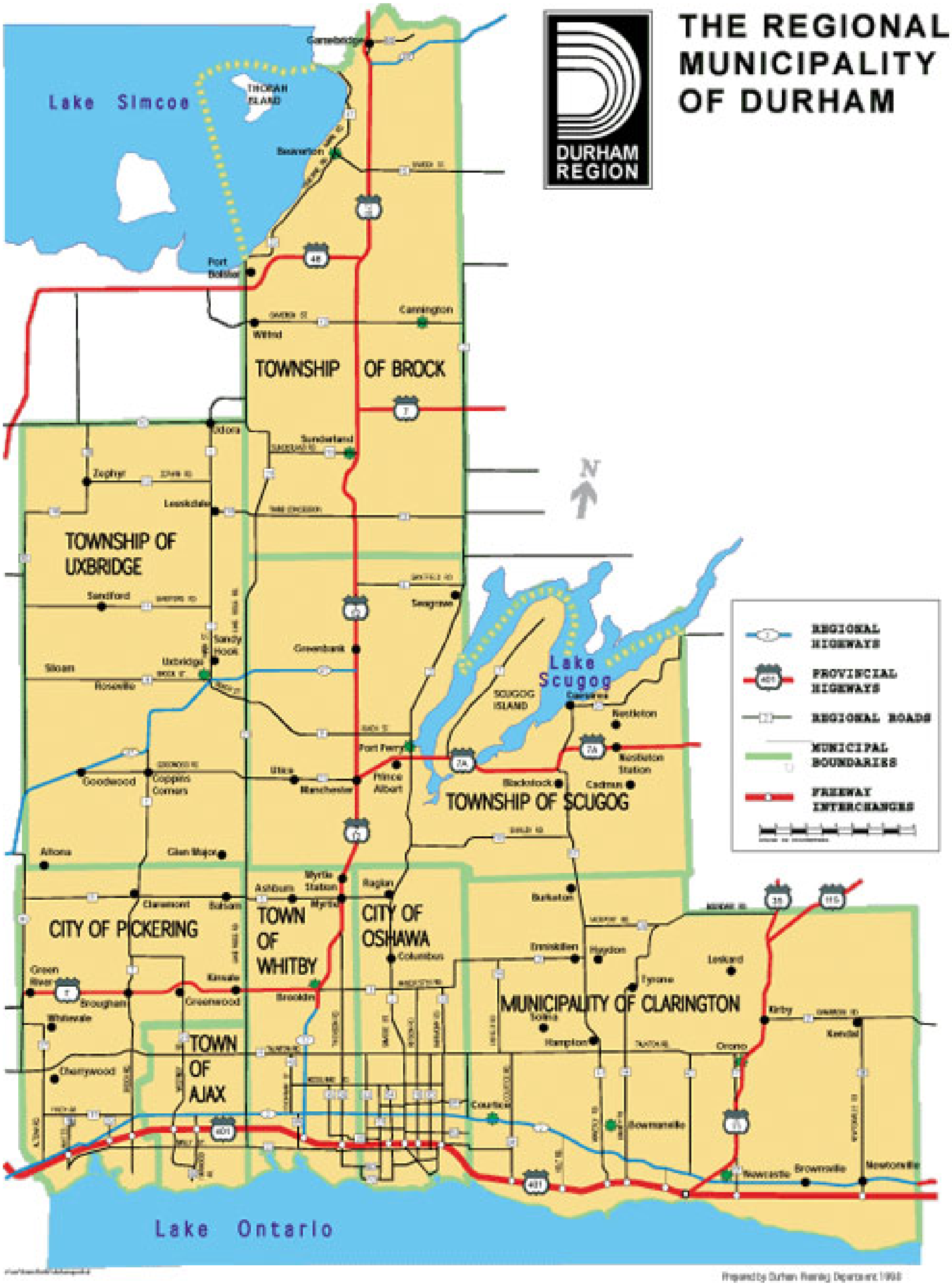
Whitby Hydro has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

Description of Distributor:

COMMUNITY SERVED:	Town of Whitby, Village of Brooklin, hamlets of Ashburn and Myrtle
TOTAL SERVICE AREA:	147.3 sq. km
RURAL SERVICE AREA:	81.46 km^2
DISTRIBUTION TYPE:	Electricity Distribution
SERVICE AREA POPULATION:	121,300
MUNICIPAL POPULATION:	121,300
BOUNDARIES:	West: Lakeridge Road
	North: Town Line Road
	East: 150 m East of Garrard Road
	South: Lake Ontario
DISTRIBUTION ASSETS:	As of December 31, 2008
44 kV Subtransmission Feeders	13
Distribution Stations	13
13.8 kV Distribution Feeders	43
Lines:	
Overhead	495 Km
Underground	535 Km
RATE BASE	$75,799,437
CUSTOMERS SERVED:	2010 Average
Residential	36,927
General Service:	
GS < 50 kW	1909
GS > 50 kW	435
Unmetered	391
Sentinel Lights	37 Lights
Streetlights	11,478 lights

Map 1-1: Whitby Hydro's location in the Regional Municipality of Durham



WHITBY HYDRO'S DISTRIBUTION SYSTEM:

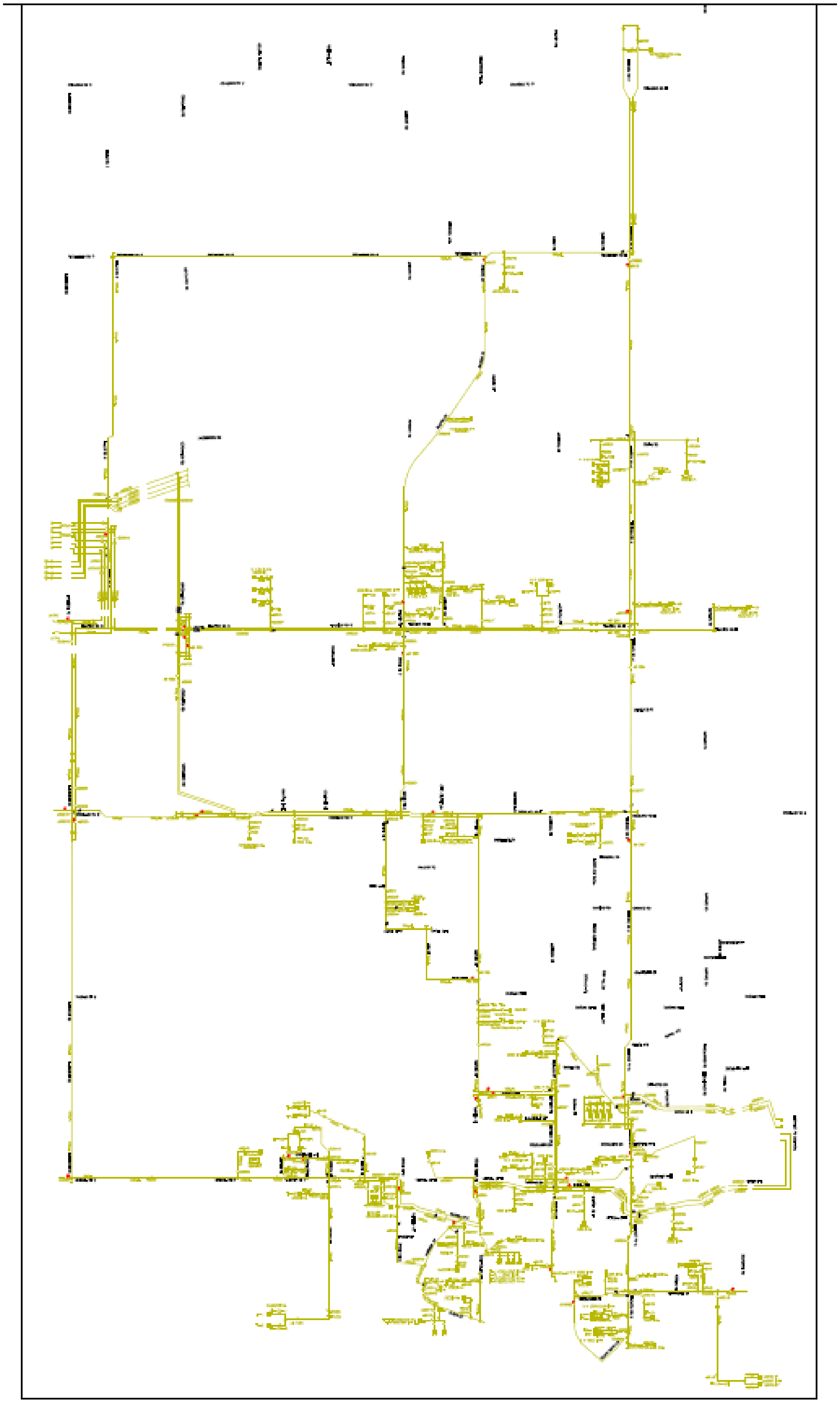
Whitby Hydro is located east of Toronto in the Regional Municipality of Durham. Whitby Hydro operates the electricity distribution system in its licensed service area. Service types include Residential, General, Unmetered and Embedded Generators.

Whitby Hydro is supplied from two (2) Hydro One Transformer Stations, namely Whitby TS and Thornton TS. There are a total of thirteen (13) 44 kV sub-transmission feeders which supply the Whitby Hydro system, of which nine (9) 44 kV feeders egress from the Whitby TS and four (4) 44 kV feeders egress from Thornton TS.

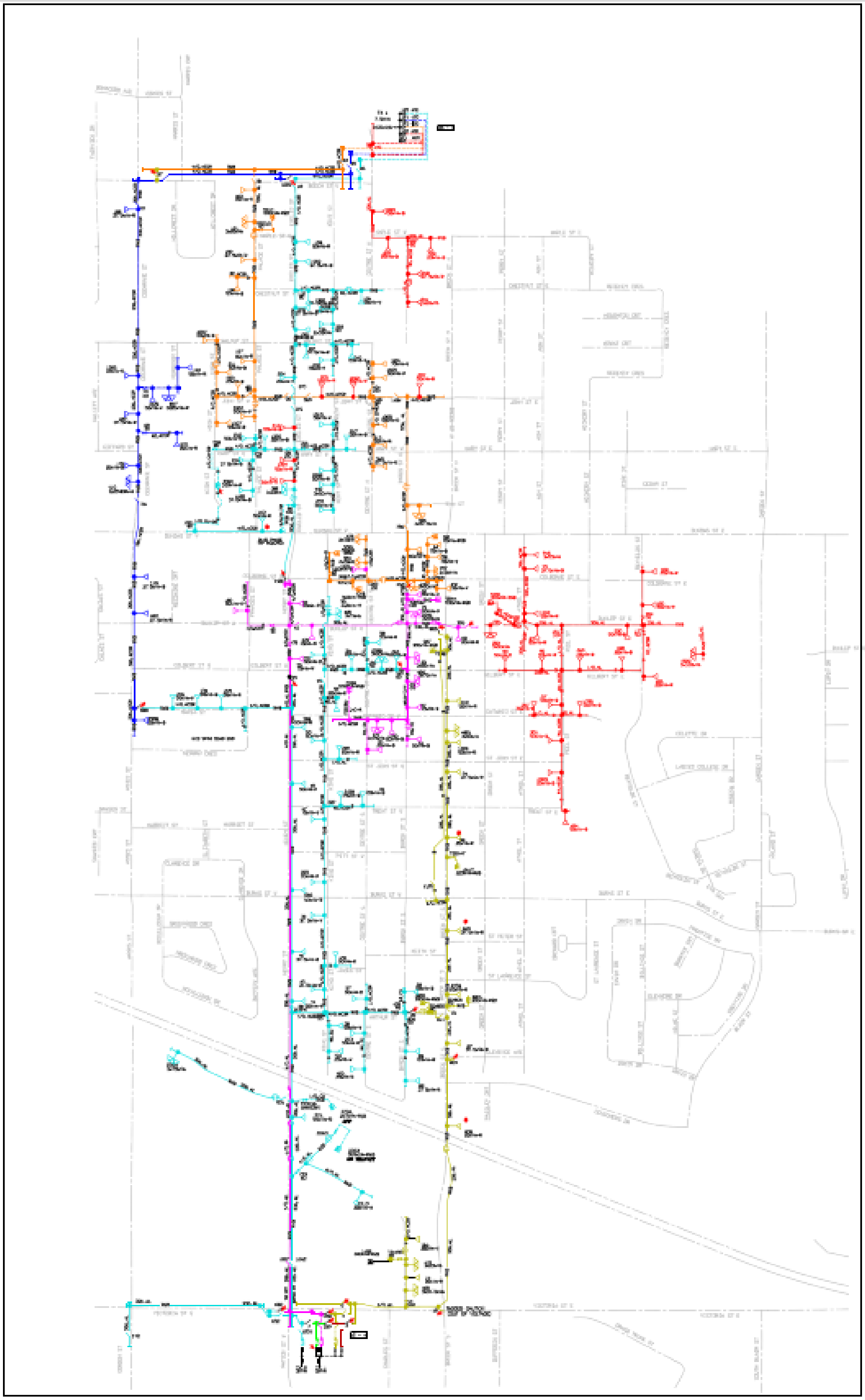
The 44 kV sub-transmission feeders supply power directly to three (3) phase customers having transformation greater than 500 kVA. The 44 kV feeders also supply power to Whitby Hydro's distribution system via municipal substations which transform the 44 kV to 13.8 kV and 4.16 kV. Three (3) phase and single (1) phase load customers with transformation up to 500 kVA are served with forty-three (43) 13.8kV and 4.16 kV feeders from the distribution stations.

Whitby Hydro monitors its sub-transmission feeders through an ICCP link to Hydro One's SCADA system. Whitby Hydro also monitors its distribution feeders through a GE Enervista Web-based SCADA system.

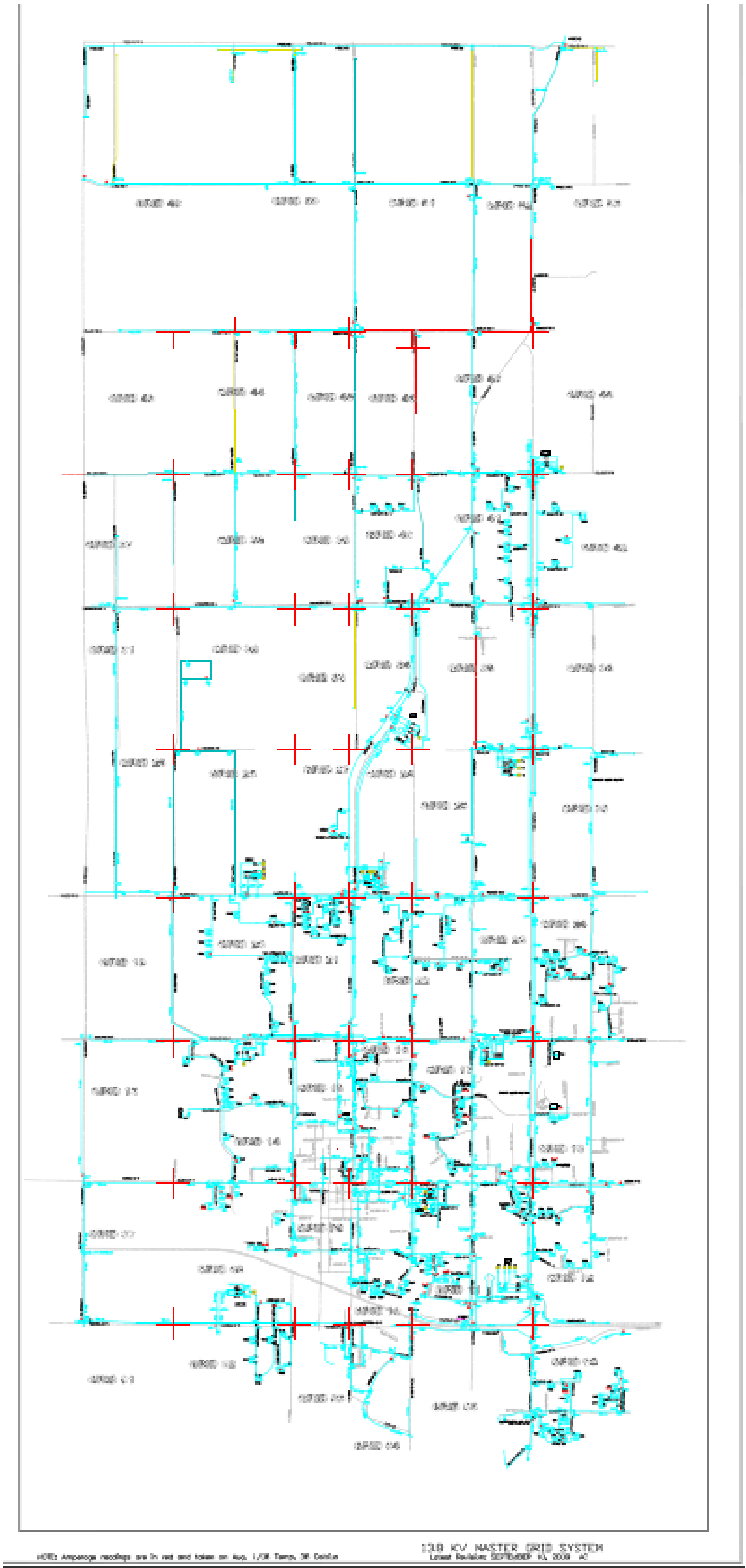
Map 1-2: Whitby Hydro's 44 kV Sub-transmission System



Map 1-3: Whitby Hydro's 13.8 kV Distribution System



Map 1-4: Whitby Hydro's 4.16 kV Distribution System



List of Neighbouring Utilities

Whitby Hydro is bounded by:

- Hydro One Networks Inc. (North)
- Veridian Connections (West)
- Oshawa P.U.C. (East)

Explanation of Host and Embedded Utilities

Whitby Hydro is a Registered Market Participant for the purposes of settlement with the Independent Electricity System Operator. However, Whitby Hydro is considered a partially "embedded" LCD because it receives some of its electricity from Hydro One Networks Inc.'s low voltage distribution system. There are no embedded utilities within Whitby Hydro's distribution territory.

CORPORATE AND UTILITY ORGANIZATIONAL STRUCTURE

The Whitby Hydro group of companies is wholly owned by the Town of Whitby. Whitby Hydro Energy Corporation (Holdco) is the Holding company for Whitby Hydro Electric Corporation (Whitby Hydro) and Whitby Hydro Energy Services Corporation (WHES).

As shown in Chart 1-2, Whitby Hydro has three Board Members, two of which also serve as Directors on the Holdco Board, while the third is independent from any other affiliates. No Holdco costs are charged to Whitby Hydro and Whitby Hydro's interaction with Holdco is limited to dividend payments. Strategic oversight and governance of Whitby Hydro is provided by the Whitby Hydro Board of Directors.

Whitby Hydro purchases operational and capital investment services under a Service Agreement with its affiliate service provider WHES. The Service Agreement is more fully discussed in Exhibit 4 and a copy has been provided (see Attachment 4-1). Whitby Hydro employs a Vice President who acts as an Asset Manager to negotiate the shared service arrangements with WHES. The VP works closely with the President and Treasurer who are officers of the company with shared responsibilities for the management of the operations, capital and assets of the regulated utility.

In order to ensure compliance with the Affiliate Relationships Code (ARC), Whitby Hydro worked collaboratively with the OEB's Chief Compliance Officer (CCO) between 2005 and 2006 as part of an ARC review and on December 1, 2006, received a letter affirming Whitby Hydro's compliance with the ARC. While Whitby Hydro understands that the CCO's views are not binding on the Board, his opinion was based on a comprehensive review of the ARC as it applied specifically to the business activities, corporate structure and shared resources (staff and information) of Whitby Hydro. Since the ARC amendments of May 16, 2008, Whitby Hydro has continued to engage in discussions with the OEB regarding interpretations so as to ensure continuing compliance with the ARC. As described in Exhibit 4, Whitby Hydro continues to rely on the operating rules and market price validation approved by the CCO to ensure ARC compliance.

Chart 1-1: Whitby Hydro Corporate Structure

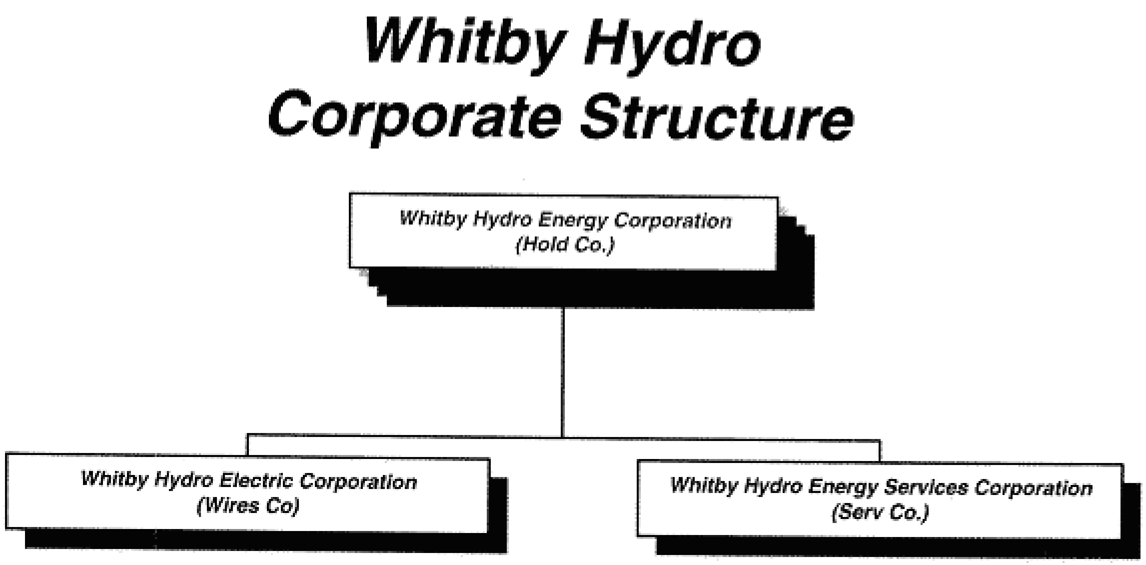
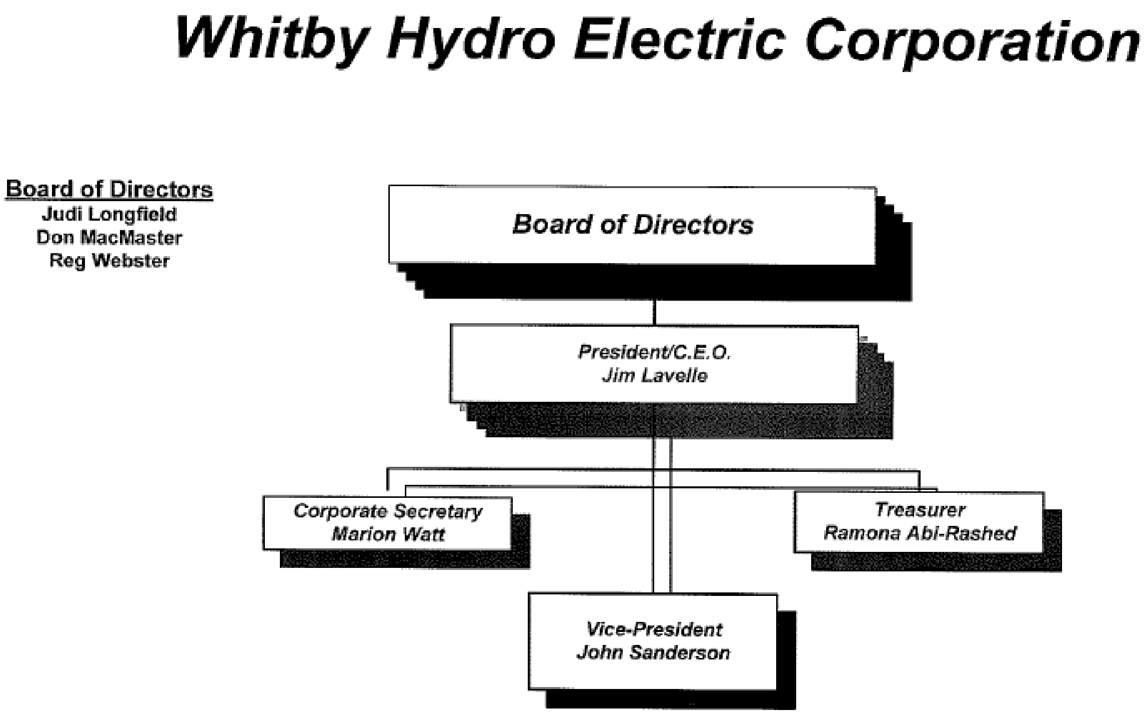


Chart 1-2: Whitby Hydro Electric Corporation Organizational Structure



PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

No changes to Whitby Hydro's corporate and operational structures are planned at the present time. Whitby Hydro will monitor developments related to the Green Energy and Environment Act to determine what services are available within the utility and which services would be potentially offered in the affiliate company to support GEA initiatives.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS

Whitby Hydro has no outstanding directives from previous Board decisions.

PRELIMINARY LIST OF WITNESSES

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

OVERVIEW

SUMMARY OF THE APPLICATION

Whitby Hydro is submitting a cost of service rate application based on a forward test year for 2010 electricity distribution rates and other specific items. Approvals are being sought for the rate year commencing May 1, 2010.

In preparing this application, Whitby Hydro has referenced and followed the Board's Filing Requirements (Updated Chapter 2) for Transmission and Distribution Applications dated May 27, 2009 as well as other documents and guidelines issued by the Board for the treatment of specific items including Smart Metering, Deferral and Variance accounts, Retail Transmission, Conservation and Demand Management and Cost of Capital.

Whitby Hydro has endeavoured to meet the Board's Filing Requirements in all relevant aspects and submits that this application and the proposed rates are just and reasonable for customers serviced by Whitby Hydro within its licensed distribution area.

This application does not address or provide for new obligations of electricity distributors under the Province's Green Energy Act (GEA) in the areas of renewable distributed generation, smart grid development and conservation and demand management. Whitby Hydro is committed to assuming its new responsibilities once the regulatory framework to support these initiatives is put in place. In this regard, Whitby Hydro plans to seek the necessary regulatory approvals for GEA related investments at a later date, once the necessary regulatory mechanisms are in place.

Overview

Whitby Hydro was established in 1903 as a Public Utilities Commission providing water and electricity distribution to consumers in the Town of Whitby. In 1974, responsibility for water distribution services was transferred to the Region of Durham. Today, Whitby Hydro distributes electricity to almost 40,000 residential and commercial customers within its regulated service area.

Historically, Whitby Hydro has prided itself on maintaining and expanding its distribution system efficiently while ensuring a good standard of safety and reliability in a time of high customer growth (52.1% from 1999-2010). In more recent years, growth continues but at a reduced rate due to the challenging economic conditions. However, this reduction in demand has been offset by increasing regulatory requirements which have put additional challenges on resources and operating activities.

Purpose and Need

Whitby Hydro has proposed a service revenue requirement of $20,747,189 for 2010 which is necessary to ensure the recovery of its costs to provide distribution services, its permitted return on equity (ROE) and the funds necessary to service the required increase in debt leverage as it transitions to a 60/40 debt to equity ratio by 2010.

Based on its forecasted energy and demand levels for 2010, Whitby Hydro estimates that its present rates will produce a gross revenue deficiency of $2,008,932 in the 2010 Test Year. The proposed rates will allow capital works, operations and maintenance of the distribution system to continue at levels necessary to maintain appropriate system reliability, safety and customer service levels.

Customer Impact

In preparing this application, Whitby Hydro has been conscious of the impacts on its customers. From this perspective, Whitby Hydro strives to manage its costs prudently while maintaining an appropriate level of service for its ratepayers.

The Streetlight, Sentinel light and Unmetered Scattered Load (USL) classes did not fall within the target ranges identified by the Board in the November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors. As a result, adjustments have been made to move these classes at least 50% towards the target range in 2010. Adjustments will continue to those classes as required to move them into the target range by 2012. The increases in distribution revenue from those classes moving closer to the target ranges will be used to reduce the revenue requirement of the Residential class. While no customer classes are above their target ranges, the Residential class is the furthest above the 100% optimum and the proposed adjustment will assist in moving the class closer to a revenue-to-cost ratio of 100%.

Customer impacts have been prepared as part of this application based on the proposed tariff of rates and charges which include distribution rates, retail transmission service rates, smart meter rate funders, LRAM and regulatory asset rate riders, proposed loss factors as well as other pass through rates. At the identified consumption levels, the following total bill impacts are as follows:

Total Bill Impacts		
Class	Typical Usage	Bill Impact
Residential	RPP @ 800 kWh	1.2%
GS < 50 kW	RPP @ 2,000 kWh	0.4%
GS > 50 kW	Non-RPP @ 100 kW; 40,000 kWh	-1.0%
USL	RPP @ 500 kWh	-3.5%
Sentinel Lights	RPP @ 1kW; 150 kWh	17.0%
Streetlights	Non-RPP @ 1kW; 150 kWh	4.6%

Since overall the rate impacts seemed reasonable and, with the exception of Sentinel Lights, none exceed the 10% rate shock threshold, the requirement for rate mitigation has not been deemed necessary. Rate mitigation was considered for the Sentinel Light customer class, but rejected once consideration was given to the low dollar impact of the proposed rates and the understanding that Sentinel Light rates make up only a small portion of those customers' "combined" bills.

Capital Expenditures

Whitby Hydro's electrical distribution assets are a key requirement in the provision of reliable, safe electricity to its customers. Since the electrical infrastructure is expanded and updated on an annual basis, the age of the distribution assets vary from very recent installations to plant dating back as far as 55 years. Whitby Hydro's asset planning process has been in place for many years and is driven by its corporate mandate to provide safe and reliable electricity and cost-effective distribution services to its customers without impairing its ability to respond efficiently to on-going customer growth and comply with evolving statutory and regulatory requirements. Capital Expenditures follow this underlying mandate with all projects being reviewed as part of the utility's approved budget process.

Net capital expenditures of $8.4M for the test year are projected to be 31% higher than the 5 year historical average as a result of a number of specific initiatives. While customer demand has recently begun to level off, additional focus has been placed on reliability works with voltage conversion and underground cable rehabilitation initiatives. Regulatory work has also increased significantly as a result of Ministry of Transportation initiatives which include the widening of Highway 7 (2010) and the 407 extension (2011 and 2012).

Capital Structure

For the purpose of preparing its 2010 rate application, Whitby Hydro used the previous Board approved cost of capital parameters and the deemed capital structure of 56% for long-term debt, 4% for short-term debt and 40% for equity. This structure has been re-affirmed by the recent Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084).

Return on Equity

In preparing its rebasing application, Whitby Hydro used an 8.01% return on equity for the 2010 Test Year in accordance with the previous Cost of Capital Parameters Updates for 2009 Cost of Service Applications as issued by the OEB on February 24th, 2009. Whitby Hydro understands that based on the recent Cost of Capital Report the OEB will be updating the capital cost information to be used for 2010 Cost of Service Rate Applications.

Operating, Maintenance and Administrative Costs (OM&A)

Whitby Hydro has been able to provide customer value while managing costs to increases of 3.63% per annum since 2004. This level of spending was largely driven by the demands of significant customer growth and the cost to maintain a safe and reliable system within an increasingly complicated regulatory environment with ongoing inflationary pressures for labour and materials.

Cost Allocation and Rate Design

The allocation of revenue responsibility is determined on the basis of the 2010 Cost Allocation Study and the proposed revenue to cost ratios outlined in Exhibit 7. Proposed fixed/variable proportions take into account existing splits and the lower and upper bounds identified for the monthly service charge. Retail Transmission Service rates and Low Voltage charges were developed in a manner designed to minimize the associated variance account balances going forward. Whitby Hydro is requesting a total loss factor of 1.0454 based on historical analysis which is a reduction from the existing loss factor approved in the 2006 EDR process.

Rate Riders

Whitby Hydro is requesting a rate rider for Regulatory Assets based on balances as of December 31, 2008 including interest to April 30, 2010. The proposed recovery period is four (4) years which matches the time period in which the balances were accumulated and serves to avoid significant rate distortion which would occur if a one-year recovery period was selected. A Lost Revenue Adjustment Mechanism (LRAM) rate rider is included in the 2010 rate application and details are provided in Exhibit 10. A utility specific Smart Meter rate funder has also been requested to provide sufficient funding to support Whitby Hydro's smart meter deployment to customers within its service territory. Further details are outlined in Exhibit 9.

WHITBY HYDRO BUDGET PROCESS

Overview

A three year capital and operating budget is prepared by Management and approved by Whitby Hydro's Board of Directors before the start of each fiscal year. The three year capital and operating budget is reviewed again in June and December and is presented to Whitby Hydro's Board for approval.

The Treasurer initiates the budget process early in the fall each year and co-ordinates the overall budget process through a timetable which sets out assumptions and milestones which must be met in order to complete the budget process for approval of the Board of Directors. Each Department Head is responsible for the three year capital and operating budget in their designated area. The President and Vice President review and approve each Department Head's budget and submit the approved amounts to the Treasurer for compilation into a final budget document. The President, Vice President and Treasurer review the budget to ensure an appropriate annual spending level that will allow Whitby Hydro to meet its core objectives of providing safe, reliable power while addressing customer growth and its regulatory and legal requirements. The President and Treasurer present the budget to the Board of Directors for approval.

Annual Capital Budget Process

Annually, Whitby Hydro reviews capital projects that have been identified through the asset management planning committee that meet the needs of its distribution system. The capital projects are prioritized based on projected load growth, required road relocation work and non-discretionary upgrades of existing electrical plant in determining timing of the budgeted projects to ensure that capital expenditure levels are relatively even on an annual basis to allow the distribution system to meet the core operating objectives. Department heads are required to identify and justify projects related to their operational area which are reviewed by the President and Vice President for approval.

The capital budget items include:

- Customer Demand
- Reliability
- Regulatory
- Subdivision Development
- Commercial Services

Capital budget items continued:

- SCADA
- Meters
- Computer Hardware
- Computer Software
- Buildings
- Office Equipment and Tools
- Land

Annual OM&A Budget Process

Similar to the capital budgeting process, a three year operating budget is prepared by management and approved by the Board of Directors before the start of each fiscal year. The three year budget is reviewed again in the following June and December and is presented to the Board of Directors for approval. Each Department Head is responsible for budgeting in their operational area based on the Board’s Uniform System of Accounts (USoA).

OM&A budgets are prepared using a zero based approach. Historical expenses and current year actuals are provided to each Department Head by the Finance Department which is used to analyze variances in spending levels and assist with forecasting and budgeting analysis. As well, variances to budget are reviewed on a monthly basis using actual data provided by the Finance Department. Items such as asset management requirements, labour contract adjustments, the assessment of revisions to department structure and responsibilities due to regulatory or industry related activities are all assessed during the budget process.

Department heads are required to identify and justify expenses related to their operational area which are reviewed by the President and Vice President for approval. The approved amounts are forwarded to the Treasurer for compilation into a final budget document which is reviewed by the President, Vice President and Treasurer to ensure an appropriate level of annual spending.

CALCULATION OF REVENUE SUFFICIENCY/DEFICIENCY

The revenue deficiency in the 2010 test year is the difference between the revenue that Whitby Hydro would earn in the test year using current rates and the revenue forecast calculated from the 2010 base revenue requirement. Whitby Hydro’s net revenue deficiency is $1,386,163 (or $2,008,932 when grossed up for PILs). A schedule outlining the revenue deficiency is included as part of the Revenue Requirement Work-form (Table 1-1). Further details of the calculation can be found in Exhibit 6.

Table 1-1: Revenue Requirement Work Form - APPENDIX 2-T

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Whitby Hydro Electric Corporation	(1)
File Number:	EB-2009-0274	
Rate Year:	2010	*Version:* *1.0*

Table of Content

Notes:

(1) Pale green cells represent inputs

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

REVENUE REQUIREMENT WORK FORM

Name of LDC: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
Rate Year: 2010

Data Input (1)

		Application		Adjustments	Per Board Decision	
1	**Rate Base**					
	Gross Fixed Assets (average)	$130,674,768	(4)		$130,674,768	
	Accumulated Depreciation (average)	($66,557,712)	(5)		($66,557,712)	
	Allowance for Working Capital:					
	Controllable Expenses	$8,919,421	(6)		$8,919,421	
	Cost of Power	$68,963,116			$68,963,116	
	Working Capital Rate (%)	15.00%			15.00%	
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$17,847,514				
	Distribution Revenue at Proposed Rates	$19,856,446				
	Other Revenue:					
	Specific Service Charges	$157,835				
	Late Payment Charges	$321,000				
	Other Distribution Revenue	$333,909				
	Other Income and Deductions	$78,000				
	Operating Expenses:					
	OM+A Expenses	$8,919,421			$8,919,421	
	Depreciation/Amortization	$4,929,391			$4,929,391	
	Property taxes					
	Capital taxes	$45,600				
	Other expenses					
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	$129,559	(3)			
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$793,034				
	Income taxes (grossed up)	$1,149,325				
	Capital Taxes	$45,600				
	Federal tax (%)	13.00%				
	Provincial tax (%)	18.00%				
	Income Tax Credits					
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(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 (%)	7.62%				
	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: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$130,674,768	$ -	$130,674,768
2	Accumulated Depreciation (average)	(3)	($66,557,712)	$ -	($66,557,712)
3	Net Fixed Assets (average)	(3)	$64,117,057	$ -	$64,117,057
4	Allowance for Working Capital	(1)	$11,682,381	$ -	$11,682,381
5	**Total Rate Base**		$75,799,437	$ -	$75,799,437

Line No.	(1) Allowance for Working Capital - Derivation		Application	Adjustments	Per Board Decision
6	Controllable Expenses		$8,919,421	$ -	$8,919,421
7	Cost of Power		$68,963,116	$ -	$68,963,116
8	Working Capital Base		$77,882,537	$ -	$77,882,537
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$11,682,381	$ -	$11,682,381

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: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$19,856,446	$ -	$19,856,446
2	Other Revenue	(1)	$890,743	$ -	$890,743
3	Total Operating Revenues		$20,747,189	$ -	$20,747,189
	Operating Expenses:				
4	OM+A Expenses		$8,919,421	$ -	$8,919,421
5	Depreciation/Amortization		$4,929,391	$ -	$4,929,391
6	Property taxes		$ -	$ -	$ -
7	Capital taxes		$45,600	$ -	$45,600
8	Other expense		$ -	$ -	$ -
9	Subtotal		$13,894,412	$ -	$13,894,412
10	Deemed Interest Expense		$3,274,839	$ -	$3,274,839
11	Total Expenses (lines 4 to 10)		$17,169,251	$ -	$17,169,251
12	**Utility income before income taxes**		$3,577,938	$ -	$3,577,938
13	Income taxes (grossed-up)		$1,149,325	$ -	$1,149,325
14	**Utility net income**		$2,428,614	$ -	$2,428,614

Notes

(1)

Other Revenues / Revenue Offsets	Application	Per Board Decision
Specific Service Charges	$157,835	$157,835
Late Payment Charges	$321,000	$321,000
Other Distribution Revenue	$333,909	$333,909
Other Income and Deductions	$78,000	$78,000
Total Revenue Offsets	$890,743	$890,743

REVENUE REQUIREMENT WORK FORM

Name of LDC: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$2,428,614	$2,428,614
2	Adjustments required to arrive at taxable utility income	$129,559	$129,559
3	Taxable income	$2,558,173	$2,558,173
	Calculation of Utility income Taxes		
4	Income taxes	$793,034	$793,034
5	Capital taxes	$45,600	$45,600
6	Total taxes	$838,634	$838,634
7	Gross-up of Income Taxes	$356,291	$356,291
8	Grossed-up Income Taxes	$1,149,325	$1,149,325
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$1,194,925	$1,194,925
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	13.00%	13.00%
12	Provincial tax (%)	18.00%	18.00%
13	Total tax rate (%)	31.00%	31.00%

Notes

REVENUE REQUIREMENT WORK FORM

Name of LDC: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Application				
	Debt				
1	Long-term Debt	56.00%	$42,447,685	7.62%	$3,234,514
2	Short-term Debt	4.00%	$3,031,977	1.33%	$40,325
3	**Total Debt**	60.00%	$45,479,662	7.20%	$3,274,839
	Equity				
4	Common Equity	40.00%	$30,319,775	8.01%	$2,428,614
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$30,319,775	8.01%	$2,428,614
7	**Total**	100%	$75,799,437	7.52%	$5,703,453
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$42,447,685	7.62%	$3,234,514
9	Short-term Debt	4.00%	$3,031,977	1.33%	$40,325
10	**Total Debt**	60.00%	$45,479,662	7.20%	$3,274,839
	Equity				
11	Common Equity	40.0%	$30,319,775	8.01%	$2,428,614
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$30,319,775	8.01%	$2,428,614
14	**Total**	100%	$75,799,437	7.52%	$5,703,453

Notes

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

REVENUE REQUIREMENT WORK FORM

Name of LDC: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$2,008,932		$2,008,932
2	Distribution Revenue	$17,847,514	$17,847,514	$17,847,514	$17,847,514
3	Other Operating Revenue Offsets - net	$890,743	$890,743	$890,743	$890,743
4	**Total Revenue**	$18,738,257	$20,747,189	$18,738,257	$20,747,189
5	Operating Expenses	$13,894,412	$13,894,412	$13,894,412	$13,894,412
6	Deemed Interest Expense	$3,274,839	$3,274,839	$3,274,839	$3,274,839
	Total Cost and Expenses	$17,169,251	$17,169,251	$17,169,251	$17,169,251
7	**Utility Income Before Income Taxes**	$1,569,006	$3,577,938	$1,569,006	$3,577,938
8	Tax Adjustments to Accounting Income per 2009 PILs	$129,559	$129,559	$129,559	$129,559
9	**Taxable Income**	$1,698,565	$3,707,497	$1,698,565	$3,707,497
10	Income Tax Rate	31.00%	31.00%	31.00%	31.00%
11	**Income Tax on Taxable Income**	$526,555	$1,149,324	$526,555	$1,149,324
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$1,042,451	$2,428,614	$1,042,451	$2,428,614
14	**Utility Rate Base**	$75,799,437	$75,799,437	$75,799,437	$75,799,437
	Deemed Equity Portion of Rate Base	$30,319,775	$30,319,775	$30,319,775	$30,319,775
15	Income/Equity Rate Base (%)	3.44%	8.01%	3.44%	8.01%
16	Target Return - Equity on Rate Base	8.01%	8.01%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-4.57%	0.00%	-4.57%	0.00%
17	Indicated Rate of Return	5.70%	7.52%	5.70%	7.52%
18	Requested Rate of Return on Rate Base	7.52%	7.52%	7.52%	7.52%
19	Sufficiency/Deficiency in Rate of Return	-1.83%	0.00%	-1.83%	0.00%
20	Target Return on Equity	$2,428,614	$2,428,614	$2,428,614	$2,428,614
21	Revenue Sufficiency/Deficiency	$1,386,163	($0)	$1,386,163	($0)
22	**Gross Revenue Sufficiency/Deficiency**	$2,008,932 **(1)**		$2,008,932 **(1)**	

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

REVENUE REQUIREMENT WORK FORM

Name of LDC: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
Rate Year: 2010

Line No.	Particulars	Revenue Requirement: Application		Revenue Requirement: Per Board Decision	
1	OM&A Expenses	$8,919,421		$8,919,421	
2	Amortization/Depreciation	$4,929,391		$4,929,391	
3	Property Taxes	$ -		$ -	
4	Capital Taxes	$45,600		$45,600	
5	Income Taxes (Grossed up)	$1,149,325		$1,149,325	
6	Other Expenses	$ -		$ -	
7	Return				
	Deemed Interest Expense	$3,274,839		$3,274,839	
	Return on Deemed Equity	$2,428,614		$2,428,614	
8	Distribution Revenue Requirement before Revenues	$20,747,189		$20,747,189	
9	Distribution revenue	$19,856,446		$19,856,446	
10	Other revenue	$890,743		$890,743	
11	**Total revenue**	$20,747,189		$20,747,189	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	**(1)**	($0)	**(1)**

Notes

(1) Line 11 - Line 8

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: Whitby Hydro Electric Corporation
File Number: EB-2009-0274
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**	$ 37.57	$ 39.50	$ 1.93	5.1%		$ 97.87	$ 99.05	$ 1.18	1.2%
GS < 50kW	**2000** kWh/month	$ 76.07	$ 79.25	$ 3.18	4.2%		$ 239.16	$ 240.17	$ 1.01	0.4%

Notes:

CHANGES IN METHODOLOGY

Whitby Hydro is not requesting any changes in methodology in the current proceeding.

FINANCIAL INFORMATION

Audited Financial Statements, 2008 (Attachment 1-1)

Proforma Balance Sheet and Income Statement, 2010, 2009 (Table 1-2 to 1-5)

Reconciliation of Regulatory Statements to Audited Statements (Table 1-6 to 1-7)

Financial statements of

Whitby Hydro Electric Corporation

December 31, 2008

Whitby Hydro Electric Corporation

December 31, 2008

Table of contents

Deloitte.

Deloitte & Touche LLP
5140 Yonge Street
Suite 1700
Toronto ON M2N 6L7
Canada

Tel: 416-601-6150
Fax: 416-601-6151
www.deloitte.ca

Auditors' Report

To the Shareholder of
Whitby Hydro Electric Corporation

We have audited the balance sheet of the Whitby Hydro Electric Corporation as at December 31, 2008 and the statements of earnings and comprehensive income and retained earnings and of cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Whitby Hydro Electric Corporation 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.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
May 4, 2009

Whitby Hydro Electric Corporation

Balance sheet
as at December 31, 2008

	2008	2007
	$	$
Assets		
Current		
Cash	**5,508,729**	6,924,201
Accounts receivable (Note 9(b)(i))	**5,336,915**	6,349,519
Unbilled revenue	**10,543,956**	8,631,248
Inventories	**941,686**	847,302
Due from the Town of Whitby	**223,476**	238,662
Prepaid expenses and deposits	**75,565**	77,313
Income taxes receivable	**195,172**	-
	22,825,499	23,068,245
Property, plant and equipment (Note 4)	**62,197,767**	58,487,808
Deferred charges	**9,169**	18,337
	85,032,435	81,574,390
Liabilities		
Current		
Accounts payable and accrued liabilities	**9,742,665**	9,303,077
Income taxes payable	-	636,447
Due to Whitby Hydro Energy Service Corporation	**373,841**	382,133
Consumer and other deposits	**754,000**	602,000
	10,870,506	10,923,657
Other liabilities		
Deferred Revenue	**339,160**	132,836
Consumer and other deposits, less amount included under current liabilities	**1,146,201**	1,095,470
Long-term debt (Note 5)	**28,337,942**	28,337,942
	29,823,303	29,566,248
	40,693,809	40,489,905
Commitments and contingencies (Notes 11 and 12)		
Equity		
Share capital		
Authorized - unlimited number of common shares		
Issued - 165 common shares	**29,494,042**	29,494,042
Retained earnings	**14,844,584**	11,590,443
	44,338,626	41,084,485
	85,032,435	81,574,390

Approved by the Board

____________________________ Director

____________________________ Director

Whitby Hydro Electric Corporation

Statement of earnings and comprehensive income and retained earnings
year ended December 31, 2008

	2008	2007
	$	$
Revenue (Note 8)	**85,016,298**	87,733,739
Energy cost	**63,774,769**	65,253,667
	21,241,529	22,480,072
Other income		
Interest	**277,097**	325,490
Late payment penalties	**321,056**	343,757
Miscellaneous	**518,828**	384,039
Rentals	**124,391**	118,473
	1,241,372	1,171,759
Expenses (Note 8)		
Operation and maintenance	**3,313,906**	3,772,382
Administration	**5,028,938**	5,130,509
Financial expense		
Interest on long-term debt	**2,000,000**	2,000,000
Other	**81,542**	103,610
Amortization of property, plant and equipment and deferred charges	**4,401,237**	4,128,555
	14,825,623	15,135,056
Earnings before income taxes	**7,657,278**	8,516,775
Income taxes (Note 7)	**2,659,137**	3,097,337
Net earnings and comprehensive income for the year	**4,998,141**	5,419,438
Retained earnings, beginning of year	**11,590,443**	7,591,005
Dividends	**(1,744,000)**	(1,420,000)
Retained earnings, end of year	**14,844,584**	11,590,443

Whitby Hydro Electric Corporation

Statement of cash flows
year ended December 31, 2008

	2008	2007
	$	$
Operating activities		
Net earnings	**4,998,141**	5,419,438
Items not affecting cash		
Loss on disposal of property, plant and equipment	**8,657**	2,607
Amortization of property, plant and equipment	**5,227,864**	4,825,627
Amortization of contributed capital	**(835,795)**	(706,240)
Amortization of deferred charges	**9,168**	9,168
	9,408,035	9,550,600
Changes in non-cash working capital components		
Accounts receivable	**1,012,604**	(478,043)
Unbilled revenue	**(1,912,708)**	14,744
Inventories	**(94,384)**	12,472
Due from the Town of Whitby	**15,186**	(44,357)
Prepaid expenses and deposits	**1,748**	(40,028)
Income taxes receivable	**(195,172)**	-
Due to Whitby Hydro Energy Services Corporation	**(8,292)**	583,277
Accounts payable and accrued liabilities	**439,588**	235,665
Income taxes payable	**(636,447)**	(302,530)
	8,030,158	9,531,800
Investing activities		
Additions to property, plant and equipment, net of property, plant and equipment contributed by third parties	**(8,110,685)**	(6,800,504)
	(8,110,685)	(6,800,504)
Financing activities		
Increase (decrease) in deferred revenue	**206,324**	(414,584)
Increase in consumer and other deposits	**202,731**	27,359
Dividends paid	**(1,744,000)**	(1,420,000)
	(1,334,945)	(1,807,225)
Net cash (outflow) inflow	**(1,415,472)**	924,071
Cash position, beginning of year	**6,924,201**	6,000,130
Cash position, end of year	**5,508,729**	6,924,201
Supplementary cash flow information		
Interest paid	**2,081,542**	2,103,610
Income taxes paid	**3,490,756**	3,399,867
Non-cash transactions		
Property, plant and equipment contributed by third parties	**3,238,879**	1,771,437

Whitby Hydro Electric Corporation
Notes to the financial statements
December 31, 2008

1. Nature of operation

Whitby Hydro Electric Corporation (the "Corporation") was incorporated November 1, 2000 under the laws of the Province of Ontario. The Corporation is indirectly, wholly-owned by the Town of Whitby. The principal activity of the Corporation is to distribute electricity to the Town of Whitby, under the license issued by the Ontario Energy Board ("OEB").

2. Significant accounting policies

The Corporation's financial statements are the representations of management, prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and reflect the following significant accounting policies.

Regulation

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

Inventories

Inventories, which consists of parts and supplies acquired for internal construction or consumption, is stated at the lower of cost and net realizable value. Cost is determined based on average cost. Any impairment losses taken on inventories are reversed if and when net realizable value subsequently recovers. Major spare parts and standby equipment are recorded as part of property, plant and equipment and amortized once they are put into use.

Property, plant and equipment and amortization

Property, plant and equipment are recorded at cost and include contracted services, materials, labour, engineering costs and overheads. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers and may be refunded by the Corporation based on economic evaluation (discounted cash flow), in accordance with the OEB Distribution System Code. Such contributions in aid of construction, whether in cash or in-kind, are offset against the related asset cost. Contributions in-kind are valued at their fair value at the date of their contribution.

When identifiable assets, such as buildings, distribution station equipment and furniture are retired or otherwise disposed of, their original cost and related accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period. The cost and related accumulated amortization of grouped assets such as transmission and distribution facilities is removed from the accounts at the end of their estimated service life.

Amortization of property, plant and equipment is provided for on the straight-line basis over the estimated service life of the assets. Amortization of contributions in aid of construction is amortized at the rates corresponding with the useful lives of the related property, plant and equipment. The estimated useful lives of the various assets used in calculating amortization are summarized below:

Buildings	50-60 years
Plant and equipment	3-10 years
Transmission and distribution systems	15-35 years
Other equipment	5-10 years

Impairment of long-lived assets

The Corporation reviews long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable and exceeds its fair value. Any resulting impairment loss is recorded in the period in which the impairment occurs.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

2. Significant accounting policies (continued)

Deferred charges

Deferred charges pertain to roadway access to right-of-way and are amortized on a straight-line basis over the term of the benefit.

Regulatory assets/liabilities

Expenditures/revenues qualifying as regulatory assets/liabilities (as defined by the OEB) and later recovered/refunded through the rate base are expensed/recorded as revenue in the year incurred/billed. Regulatory assets and liabilities are disclosed in the notes to the financial statements.

Revenue recognition

Energy and distribution revenue is recorded on the basis of regular meter readings plus estimates of customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power consumed.

Deferred revenue

As part of the Ontario Government's Smart Meter initiative to install smart meters throughout Ontario by 2010, the Corporation has recorded the amounts collected from customers in deferred revenue and capital spending to date is recorded as part of property, plant and equipment and, will be amortized once the Smart Meters are put into use.

Financial instruments

Financial assets and liabilities are initially recorded at fair value. The fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act. Subsequent measurement depends on how each financial instrument is classified on the balance sheet.

The Corporation has made the following balance sheet classifications in connection with its financial assets and financial liabilities:

- Cash is classified as a financial asset "Held-for-Trading" and is measured at fair value.
- Accounts receivable and due from the Town of Whitby are classified as "Loans and Receivables" and are measured at amortized cost using the effective interest method.
- Accounts payable and accrued liabilities, consumer and other deposits and long-term debt are classified as "Other Financial Liabilities" and measured at amortized cost using the effective interest method.

Consumer deposits

Consumer deposits are cash collected from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as a current liability. Interest is paid on consumer balances at rates established from time to time by the Corporation.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

2. Significant accounting policies (continued)

Payments-in-lieu of income taxes

In accordance with Ontario Regulation 162/01 made under the Electricity Act, 1998, the Corporation provides for payments-in-lieu of corporate taxes ("PILs") to the Ontario Electricity Financial Corporation (OEFC), commencing October 1, 2001. 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 Corporation, regulated by the Ontario Energy Board, 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. Rate-regulated enterprises need not recognize future income taxes to the extent that future income taxes are expected to be included in the rates charged to and recovered from future customers.

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

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of revenues, expenses, assets and liabilities, as well as disclosure of contingent assets and liabilities in the financial statements and accompanying notes. Accounts receivable, unbilled revenue and inventories are reported based on amounts expected to be recovered and an appropriate allowance has been provided based on management's best estimates of unrecoverable amounts. Due to the inherent uncertainty in making such estimates, actual results could differ from those estimates.

3. Changes in accounting policies

Current changes

(a) Inventories

Effective January 1, 2008, the Corporation adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 - Inventories, which replaced the existing Section 3030-Inventory. Under the new Section, inventories are required to be measured at the lower of cost and net realizable value. The new Handbook section also allows impairment losses taken on inventories to be reversed if and when net realizable value subsequently recovers.

In addition this new section requires that major spare parts and standby equipment be reclassified from inventory to property, plant and equipment. The adoption of this new section did not have any impact on the financial statements.

(b) Financial instruments disclosures and presentation

In December 2006, the CICA issued Section 3862, Financial Instruments - Disclosures; Section 3863, Financial Instruments - Presentation which are applicable to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. Accordingly, the Corporation adopted the new standards for its fiscal year beginning January 1, 2008.

Section 3862 requires the disclosure of information about: i) the significance of financial instruments for the Corporation's financial position and performance; and ii) the nature and extent of risks arising from financial instruments to which the Corporation is exposed during the period and at the balance sheet date, and how the Corporation manages those risks. The additional disclosures have been provided in Note 9.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

3. Changes in accounting policies (continued)

(b) Financial instruments disclosures and presentation (continued)

Section 3863 on the presentation of financial instruments is unchanged from the presentation requirements included in Section 3861, Financial Instruments - Disclosure and Presentation, and, therefore, adoption of this new standard did not have any impact on the financial statements.

(c) Capital disclosures

CICA Handbook Section 1535, Capital Disclosures requires disclosure of the Corporation's objectives, policies and processes for managing capital as well as its compliance with any external capital requirements. The standard is effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007. Accordingly, the Corporation adopted the new standard for its fiscal year beginning on January 1, 2008 and the required disclosure is provided in Note 15. The implementation of this standard did not have any impact on the Corporation's results of operations or financial position.

Future accounting changes

(a) Rate-regulated operations

Effective January 1, 2009, the temporary exemption from CICA Section 1100, "Generally Accepted Accounting Principles" which permits the recognition and measurement of assets and liabilities arising from rate regulation will be withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax liabilities and assets. As a result of these changes, the Corporation will be required to recognize future incomes tax liabilities and assets instead of using the taxes payable method. These changes will be applied prospectively beginning January 1, 2009.

The Corporation is currently evaluating the impact of these changes on its financial statements.

(b) Goodwill and intangible assets

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Corporation will adopt the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises.

The Corporation is currently evaluating the impact of the adoption of this new Section on its financial statements.

(c) Transition to International Financial Reporting Standards ("IFRS")

The Accounting Standards Board has adopted a new strategic plan that will have GAAP converge with IFRS, effective January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of the amounts reported by the Corporation for its year ending December 31, 2010, and the opening balance sheet as at January 1, 2010.

The Corporation is continuing to assess the financial reporting impacts of the adoption of IFRS.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

4. Property, plant and equipment

			2008	2007
	Cost	Accumulated amortization	Net book value	Net book value
	$	$	$	$
Land	**438,972**	**-**	**438,972**	438,972
Buildings, plant and equipment	**21,258,161**	**7,696,029**	**13,562,132**	11,874,012
Transmission and distribution systems	**114,667,016**	**51,432,741**	**63,234,275**	59,497,804
Other equipment	**5,676,998**	**4,174,710**	**1,502,288**	1,420,337
Smart Meters - Work in progress	**606,500**	**-**	**606,500**	-
	142,647,647	**63,303,480**	**79,344,167**	73,231,125
Contributions in aid of construction	**(20,894,884)**	**(3,748,484)**	**(17,146,400)**	(14,743,317)
	121,752,763	**59,554,996**	**62,197,767**	58,487,808

Net amortization provided for in the current year totalled $4,392,069 (2007 - $4,119,387).

5. Long-term debt

	2008	2007
	$	$
7-1/4% promissory note issued to the Town of Whitby. The Town has the option of calling the principal amount in whole or in part with sixty days notice. The Town of Whitby does not anticipate calling this note before January 1, 2010	**1,460,300**	1,460,300
7-1/4% promissory note issued to the Town of Whitby. The Town has the option of calling the principal amount in whole or in part with sixty days notice. The Town of Whitby does not anticipate calling this note before January 1, 2010	**5,061,000**	5,061,000
7 % promissory note issued to the Town of Whitby. The Town has the option of calling the principal amount in whole or in part with twelve months notice. The Town of Whitby does not anticipate calling this note before January 1, 2010	**21,816,642**	21,816,642
	28,337,942	28,337,942

Interest on long-term debt is $2,000,000 (2007 - $2,000,000).

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

6. Credit facility

The Corporation requested and received an unsecured credit facility with a Canadian chartered bank and the related agreement was executed on April 8, 2002. This facility is uncommitted and repayment is due on demand. This credit facility agreement allows for Letters of Credit up to $6.9 million and provides a revolving credit facility of $2 million. As at December 31, 2008, the Corporation had utilized $5,393,461 of the credit facility to provide IESO with a letter of credit for prudential support. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. The existing credit facility can be drawn upon by either direct advances bearing interest at prime or by way of letter of credit with a fee of 50 basis points per annum.

7. Income taxes

The Corporation became obligated to make payments-in-lieu of corporate taxes on October 1, 2001. There were no income or capital taxes in the periods prior to October 1, 2001.

The provision for income taxes under the taxes payable method for the year is $2,659,137 (2007 - $3,097,337).

Future income taxes have not been recorded in the accounts as they are expected to be reflected through future distribution revenues. As at December 31, 2008, future income tax assets (primarily related to property, plant and equipment) of $2,679,253 (2007 - $2,635,610) have not been recorded on the balance sheet. Future income tax (recovery) expense of $(43,643) (2007 – $291,610) has not been reflected in the income tax provision for the year ended December 31, 2008.

8. Related party transactions

The following summarizes the Corporation's related party transactions with the Town of Whitby for the years ended December 31, 2008 and December 31, 2007:

	2008	2007
	$	$
Revenue		
Energy and distribution	**2,475,842**	2,802,712
Expenses		
Interest expense	**2,000,000**	2,000,000
Property taxes	**235,622**	213,888
Other	**-**	30,000

Whitby Hydro Electric Corporation
Notes to the financial statements
December 31, 2008

8. Related party transactions (continued)

The following summarizes the Corporation's related party transactions with associated companies (companies under common control) for the years ended December 31, 2008 and December 31, 2007.

	2008	2007
	$	$
Conservation Demand Management	**212,691**	455,098
Vehicle replacement	**493,898**	452,010
Capital services	**6,210,285**	6,205,266
Operation and maintenance and administrative services	**6,199,933**	6,308,572

The above noted charges are pursuant to an annual agreement with Whitby Hydro Energy Service Corporation.

9. Financial instruments and risk management

(a) *Recognition and measurement*

CICA Handbook Section 3855 established the standards for recognizing and measuring financial assets and financial liabilities and the standards for reporting gains and losses in the financial statements. The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 2.

The review of all existing contracts substantiates that the Corporation does not currently have any contracts containing embedded derivatives that need to be accounted for separately at fair value.

The fair value of the Corporation's cash, accounts receivable, accounts payable and accrued liabilities and refundable consumer deposits approximate their carrying amount because of the short term maturity of these instruments.

The fair value of the Corporation's promissory notes payable to the Corporation of the Town of Whitby and due to/from related parties is not determined due to their related party nature and variable terms.

(b) *Risk management*

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

(i) Credit risk

The Corporation's primary source of credit risks to its accounts receivable result from customer's failing to discharge their dues for electricity consumed and billed. The Corporation has approximately 39,000 residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits amounting to $1,900,201 in accordance with OEB guidelines, in-house collection department as well as external collection agencies. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

9. Financial instruments and risk management (continued)

(b) Risk management (continued)

(i) Credit risk (continued)

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

	2008		2007	
	Total	**%**	Total	%
	$		$	
Less than 30 days	**5,074,910**	**86**	6,131,388	92
30 - 60 days	**276,213**	**5**	133,816	2
61 - 90 days	**97,219**	**1**	66,209	1
Greater than 91 days	**480,108**	**8**	353,525	5
Outstanding	**5,928,450**	**100**	6,684,938	100
Less: Allowance for doubtful	**(591,535)**		(335,419)	
	5,336,915		6,349,519	

As at December 31, 2008, there was no significant concentration of credit risk with respect to any class of financial assets.

(ii) Interest rate risk

The Corporation has limited exposure to interest rate risk as its long-term debt consists entirely of fixed rate debt in the form of promissory notes with its shareholder, the Town of Whitby. The Corporation ensures that all payment obligations are met by adopting proper capital planning.

The Corporation has an unsecured credit facility with a Canadian chartered bank for the purpose of providing the IESO with a letter of credit for prudential support as well as providing a revolving credit facility, details of which are disclosed in Note 6.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.75% per annum. These interest rate fluctuations could impact the level of interest income earned by the Corporation.

(iii) Hedging and derivatives risk

The Corporation has not entered into hedging and derivative financial instruments and hence the Corporation is not exposed to risks of this nature. The Corporation does not have commodity price risk.

(iv) Foreign exchange risk

The Corporation has minimal exposure to fluctuations in foreign currencies. The Corporation purchases goods and services from the US which are payable in US dollars, however the impact of these transactions to the financial statements are minimal.

In addition to the above, the Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members. Insurance premiums charged to each member consist of a levy per thousands of dollar of service revenue subject to a credit or surcharge based on each member's claims experience. Coverage is provided to a level of $24 million per incident.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

10. Interest in limited partnership

The Corporation sold its shares in EnerConnect, a power procurement partnership under a three year staged cash payout with a $7,139 payment for 2007 and $4,760 for 2008. In 2007, Whitby Hydro Electric Corporation had a 1.587% interest in this partnership. The investment of $46,389 was expensed in the years in which it was made.

11. Future commitments

The Corporation has entered into an agreement with a service provider and is committed to making the following payments:

	$
2009	69,240
2010	69,240
2011	23,080
	161,560

12. Contingencies

Class action of late payment charges

Griffith et al. v. Toronto Hydro-Electric Commission et al.

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

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

Whitby Hydro collected total late payment penalties of $2,081,699 for the period from 1994 to 2001. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

13. Regulatory accounts

	2008	2007
	$	$
Regulatory accounts (including carrying charges)		
Regulatory accounts - Post 2004		
Government cheques rebate program	**1,330**	1,223
Retail costs variance		
Retail services	**232,500**	194,253
STR requests and processing	**(1,144)**	(838)
Retail settlement variance		
Transmission network charge	**(1,300,935)**	(501,896)
Transmission connection charge	**(1,367,707)**	(585,237)
Wholesale market service	**(2,096,175)**	(1,434,356)
Power energy cost	**(971,102)**	148,360
Global adjustment	**460,408**	116,435
Low voltage variance	**(69,407)**	(64,378)
Smart Meters	**255,323**	(138,896)
	(4,856,909)	(2,265,330)
Regulatory accounts and approved recoveries		
Recovery of regulatory accounts	**(6,501,671)**	(5,627,409)
Unrecovered regulatory accounts prior years	**5,609,704**	5,441,383
Regulatory Accounts Hydro One charges	**412,607**	400,239
	(479,360)	214,213
Deferred payments-in-lieu of taxes	**(1,633,297)**	(1,579,726)
	(6,969,566)	(3,630,843)

The Corporation does not record regulatory assets or regulatory liabilities on its balance sheet but provides disclosure of these regulatory accounts as noted above.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

14. Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee. The Corporation's primary guarantees subject to disclosure requirements are as follows:

(a) Indemnity has been provided to all directors and or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(b) In the normal course of business, the Corporation has entered into agreements that include indemnities in favour of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The term of these indemnities are not explicitly defined and the maximum amount of any potential reimbursements cannot be estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2008

15. Capital disclosures

The Corporation's main objectives in the management of capital are to:

(i) Consistently maintain a high credit rating for the Corporation.

(ii) Deliver appropriate financial returns to the shareholders.

The Corporation considers Equity and Long-term debt as its Capital. The capital structure as at December 31, 2008 in comparison to December 31, 2007 is as follows:

	2008	2007
	$	$
Equity		
Share capital	**29,494,042**	29,494,042
Retained earnings	**14,844,584**	11,590,443
Total	**44,338,626**	41,084,485
Long-term debt (Note 5)	**28,337,942**	28,337,942
Total capital	**72,676,568**	69,422,427

16. Comparative figures

Certain prior year's comparative figures have been reclassified to conform to the current year's presentation.

Attachment 1-2: Audited Financial Statements, 2007

Financial statements of

Whitby Hydro Electric Corporation

December 31, 2007

Whitby Hydro Electric Corporation
December 31, 2007

Table of contents

Deloitte.

Deloitte & Touche LLP
5140 Yonge Street
Suite 1700
Toronto ON M2N 6L7
Canada

Tel: 416-601-6150
Fax: 416-601-6151
www.deloitte.ca

Auditors' Report

To the Shareholder of
Whitby Hydro Electric Corporation

We have audited the balance sheet of the Whitby Hydro Electric Corporation as at December 31, 2007 and the statements of earnings and comprehensive income and retained earnings and of cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Whitby Hydro Electric Corporation 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.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
March 4, 2008

Whitby Hydro Electric Corporation

Balance sheet
December 31, 2007

	2007	2006
	$	$
Assets		
Current		
Cash	**6,924,201**	6,000,130
Accounts receivable	**6,349,519**	5,871,476
Unbilled revenue	**8,631,248**	8,645,992
Inventory	**847,302**	859,774
Due from Town of Whitby	**238,662**	194,305
Prepaid expenses and deposits	**77,313**	37,285
Due from Whitby Hydro Energy Service Corporation	**-**	201,144
	23,068,245	21,810,106
Property, plant and equipment (Note 4)	**58,487,808**	55,809,298
Other assets - Deferred charges	**18,337**	27,505
	81,574,390	77,646,909
Liabilities		
Current		
Accounts payable and accrued liabilities	**9,435,913**	9,067,412
Deferred revenue	**-**	547,420
Income taxes payable	**636,447**	938,977
Due to Whitby Hydro Energy Service Corporation	**382,133**	-
Consumer and other deposits	**602,000**	554,858
	11,056,493	11,108,667
Other liabilities		
Consumer and other deposits, less amount included under current liabilities	**1,095,470**	1,115,253
Long-term debt (Note 5)	**28,337,942**	28,337,942
	29,433,412	29,453,195
	40,489,905	40,561,862
Commitments and contingencies (Notes 11 and 12)		
Equity		
Share capital		
Authorized - unlimited number of common shares		
Issued - 165 common shares	**29,494,042**	29,494,042
Retained earnings	**11,590,443**	7,591,005
	41,084,485	37,085,047
	81,574,390	77,646,909

Approved by the Board

_______________________________ Director

_______________________________ Director

Whitby Hydro Electric Corporation

Statement of earnings and comprehensive income and retained earnings
year ended December 31, 2007

	2007	2006
		(Note 15)
	$	$
Revenue (Note 8)	**87,733,739**	84,397,254
Energy cost	**65,253,667**	64,431,202
	22,480,072	19,966,052
Other income		
Interest	**325,490**	260,813
Late payment penalties	**343,757**	297,895
Miscellaneous	**384,039**	312,832
Rentals	**118,473**	105,854
	1,171,759	977,394
Expenses (Note 8)		
Operation and maintenance	**3,772,382**	3,310,340
Administration	**5,130,509**	5,029,673
Financial expense		
Interest on long-term debt	**2,000,000**	2,000,000
Other	**103,610**	100,853
Amortization of property, plant and equipment and deferred charges	**4,128,555**	3,896,885
	15,135,056	14,337,751
Earnings before income taxes	**8,516,775**	6,605,695
Income taxes (Note 7)	**3,097,337**	2,503,446
Net earnings and comprehensive income	**5,419,438**	4,102,249
Retained earnings, beginning of year	**7,591,005**	4,028,756
Dividends	**(1,420,000)**	(540,000)
Retained earnings, end of year	**11,590,443**	7,591,005

Whitby Hydro Electric Corporation

Statement of cash flows
year ended December 31, 2007

	2007	2006
		(Note 15)
	$	$
Net inflow (outflow) of cash related to the following activities		
Operating		
Net earnings and comprehensive income	**5,419,438**	4,102,249
Items not affecting cash		
Loss on disposal of property, plant and equipment	**2,607**	2,958
Amortization of property, plant and equipment	**4,825,627**	4,523,098
Amortization of contributed capital	**(706,240)**	(635,383)
Amortization of deferred charges	**9,168**	9,170
	9,550,600	8,002,092
Changes in non-cash working capital components		
Accounts receivable	**(478,043)**	(1,977,450)
Unbilled revenue	**14,744**	1,806,775
Inventory	**12,472**	(94,241)
Due from Town of Whitby	**(44,357)**	(2,476)
Prepaid expenses and deposits	**(40,028)**	(12,195)
Due from Whitby Hydro Energy Services Corporation	**583,277**	166,082
Accounts payable and accrued liabilities	**368,501**	(2,518,214)
Income taxes payable	**(302,530)**	(204,759)
	9,664,636	5,165,614
Investing		
Additions to property, plant and equipment, net of property, plant and equipment contributed by third parties	**(6,800,504)**	(6,468,970)
Financing		
Decrease in deferred revenue	**(547,420)**	(469,290)
Increase in consumer and other deposits	**27,359**	113,167
Dividends	**(1,420,000)**	(540,000)
	(1,940,061)	(896,123)
Net cash inflow (outflow)	**924,071**	(2,199,479)
Cash position, beginning of year	**6,000,130**	8,199,609
Cash position, end of year	**6,924,201**	6,000,130
Supplementary cash flow information		
Interest paid	**2,103,610**	2,100,853
Income taxes paid	**3,399,867**	2,708,205
Non-cash transactions		
Capital assets contributed by third parties	**1,771,437**	2,295,607

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

1. Nature of operation

Whitby Hydro Electric Corporation ("the Corporation") was incorporated November 1, 2000 under the laws of the Province of Ontario. The Corporation is indirectly, wholly-owned by the Town of Whitby. The principal activity of the Corporation is to distribute electricity to the Town of Whitby, under the license issued by the Ontario Energy Board (OEB).

2. Significant accounting policies

The financial statements are the representations of management, prepared in accordance with Canadian generally accepted accounting principles (GAAP) and reflect the following policies.

Regulation

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

Inventory

Inventories are valued at the lower of average cost and replacement cost.

Property, plant and equipment and amortization

Property, plant and equipment are recorded at cost and include contracted services, materials, labour, engineering costs and overheads. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers and may be refunded by the Corporation based on economic evaluation (discounted cash flow), in accordance with the OEB Distribution System Code. Such contributions, whether in cash or in-kind, are offset against the related asset cost. Contributions in-kind are valued at their fair value at the date of their contribution.

When identifiable assets, such as buildings, distribution station equipment and equipment and furniture are retired or otherwise disposed of, their original cost and related accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period.

Amortization of property, plant and equipment is provided for on the straight-line basis over the estimated service life of the assets. Amortization of contributions from developers or customers is amortized at the rates corresponding with the useful lives of the related capital assets. The estimated service lives of the various assets used in calculating amortization are summarized below:

Building	50-60 years
Plant and equipment	3-10 years
Transmission and distribution system	15-35 years
Office equipment	5-10 years

Impairment of long-lived assets

The Corporation reviews long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable and exceeds its fair value. Any resulting impairment loss is recorded in the period in which the impairment occurs.

Deferred charges

Deferred charges pertain to roadway access to right-of-way and are amortized on a straight-line basis over the term of the benefit.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

2. Significant accounting policies (continued)

Regulatory assets / liabilities

Expenditures / revenues qualifying as regulatory assets / liabilities (as defined by the OEB) and later recovered / refunded through the rate base are expensed / recorded as revenue in the year incurred / billed.

Revenue recognition

Energy and distribution revenue is recorded on the basis of regular meter readings plus estimates of customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power consumed.

Deferred revenue

In 2006, the Corporation collected the final installment (fourth tranche) of OEB regulated funds related to conservation and demand management (CDM). These excess recoveries (deferred revenue) have been recognized in 2007 when the Corporation discharged its obligation related to CDM spending.

Consumer deposits

Consumer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as a current liability. Interest is paid on consumer balances at rates established from time to time by the Corporation.

Payment in lieu of income taxes

Under the Electricity Act, 1998, the Corporation is required to make payments-in-lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC), commencing October 1, 2001. 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 Corporation, regulated by the Ontario Energy Board, 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. Rate-regulated enterprises need not recognize future income taxes to the extent that future income taxes are expected to be included in the rates charged to and recovered from future customers.

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

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of revenues, expenses, assets and liabilities, as well as disclosure of contingent assets and liabilities in the financial statements and accompanying notes. Accounts receivable, unbilled revenue and inventory are reported based on amounts expected to be recovered and an appropriate allowance has been provided based on management's best estimates of unrecoverable amounts. Due to the inherent uncertainty in making such estimates, actual results could differ from those estimates.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

3. Accounting changes

(a) Changes in accounting policies for 2007

Effective January 1, 2007, the Corporation adopted the accounting requirements of the Canadian Institute of Chartered Accountants ("CICA") Handbook Sections 1506 "Accounting Changes", 1530 "Comprehensive Income", 3251 "Equity", 3855 "Financial Instruments – Recognition and Measurement"; 3861 – "Financial Instruments – Disclosure and Presentation"; and 3865 – "Hedges".

(i) Financial instrument-recognition and measurement (Section 3855)

This Section established the standards for recognizing and measuring financial assets and financial liabilities and the standards for reporting gains and losses in the financial statements. Financial assets and liabilities are initially recorded at fair value. Subsequent measurement depends on how each financial instrument is classified on the balance sheet.

As of January 1, 2007, the Corporation has made the following balance sheet classifications in connection with its financial assets and financial liabilities:

Cash, accounts payable and accrued liabilities and income taxes payable are classified as "Held-for-Trading" and are measured at fair value.

Accounts receivable and due from the Town of Whitby are classified as "Loans and Receivables" and are measured at amortized cost using the effective interest method.

Consumer and other deposits and long-term debt are classified as "Other Financial Liabilities" and measured at amortized cost using the effective interest method.

(ii) Comprehensive income (Section 1530)

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which has not been included in net income.

The Corporation had no adjustments to other comprehensive income during the year-ended December 31, 2007.

(iii) Hedges (Section 3865)

These recommendations expand the guidelines outlined in Accounting Guideline 13 ("AcG-13"), Hedging Relationships. This section describes when and how hedge accounting can be applied, as well as disclosure requirements. Hedge accounting enables the recording of gains, losses, revenue and expenses from the derivative financial instruments in the same period as for those related to the hedged item. As at December 31, 2007, the Corporation has not engaged in any hedging transactions and none of its financial instruments have been designated for hedge accounting.

(iv) Transaction costs - effective interest method (Section 3855)

Transactions costs will be capitalized to the cost of financial assets and liabilities classified as other than held for trading and the effective interest method used to amortize those transaction costs. The effective interest method requires the use of a constant yield rate based on expected cash flows to amortize transaction costs and record the related interest income/expense. The Corporation does not have any transaction costs.

(v) Embedded derivatives

The Corporation reviewed active contracts as of the transition date for any embedded derivatives. Based on a review of the Corporation's financial instruments as at January 1, 2007, there were no embedded derivatives at that date that were required to be accounted for separately as derivatives.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

3. Accounting changes (continued)

(b) Future accounting changes

(i) Inventories

In June 2007, CICA issued Section 3031, Inventories, replacing Section 3030, Inventories. The new Section will be applicable to financial statements relating to fiscal years beginning on or after January 1, 2008. Accordingly, the Corporation will adopt the new standards for its fiscal year beginning January 1, 2008. Under the new standard, inventories are required to be measured at the lower of cost and net realizable value. The standard also provides updated measurement and disclosure requirements for inventories. The Corporation is currently evaluating the impact of the adoption of this new section on its financial statements.

(ii) Financial instruments

In December 2006, the CICA issued Section 3862, Financial Instruments - Disclosures; Section 3863, Financial Instruments - Presentation; and Section 1535, Capital Disclosures. All three Sections will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2007. Accordingly, the Corporation will adopt the new standards for its fiscal year beginning January 1, 2008. Section 3862 on financial instruments disclosures, requires the disclosure of information about: a) the significance of financial instruments for the entity's financial position and performance and b) the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. Section 3863 on the presentation of financial instruments is unchanged from the presentation requirements included in Section 3861. Section 1535 on capital disclosures requires the disclosure of information about an entity's objectives, policies and processes for managing capital as well as its compliance with capital requirements. The Corporation is currently evaluating the impact of the adoption of these new Sections on its financial statements.

(iii) Goodwill and intangible assets

In February 2008, the CICA issued Section 3064, Goodwill and intangible assets, replacing Section 3062, Goodwill and other intangible assets and Section 3450, Research and development costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Sections will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Corporation will adopt the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Corporation does not expect that the adoption of this new Section will have an impact on its financial statements.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

3. Accounting changes (continued)

(b) Future accounting changes (continued)

(iv) Rate-regulated operations

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100, "Generally Accepted Accounting Principles" which permits the recognition and measurement of assets and liabilities arising from rate regulation, will be withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax liabilities and assets. As a result of the changes, Whitby Hydro Electric Corporation will be required to recognize future incomes tax liabilities and assets instead of using the taxes payable method, and will record an offsetting adjustment to opening retained earnings. These changes will be applied prospectively beginning January 1, 2009. The Corporation is currently evaluating the impact these changes will have on its financial statements.

(v) International Financial Reporting Standards

The CICA's Accounting Standards Board (AcSB) announced that Canadian publicly accountable enterprises will adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian GAAP, differences in accounting policies will need to be addressed. The Corporation is currently assessing the impact of this AcSB announcement, on its financial statements.

4. Property, plant and equipment

			2007	2006
	Cost	Accumulated amortization	Net book value	Net book value
	$	$	$	$
Land	438,972	-	438,972	438,972
Buildings, plant and equipment	18,988,410	7,114,398	11,874,012	11,785,640
Transmission and distribution system	106,681,489	47,183,685	59,497,804	55,852,718
Other equipment	5,224,381	3,804,044	1,420,337	1,410,088
	131,333,252	58,102,127	73,231,125	69,487,418
Contributions in aid of construction	(17,656,006)	(2,912,689)	(14,743,317)	(13,678,120)
	113,677,246	55,189,438	58,487,808	55,809,298

Net amortization provided for in the current year totalled $4,119,387 (2006 - $3,887,715).

Whitby Hydro Electric Corporation
Notes to the financial statements
December 31, 2007

5. Long-term debt

	2007	2006
	$	$
7-1/4% promissory note issued to the Town of Whitby. The Town has the option of calling the principal amount in whole or in part with sixty days notice. The Town of Whitby does not anticipate calling this note before January 1, 2009	**1,460,300**	1,460,300
7-1/4% promissory note issued to the Town of Whitby. The Town has the option of calling the principal amount in whole or in part with sixty days notice. The Town of Whitby does not anticipate calling this note before January 1, 2009	**5,061,000**	5,061,000
7 % promissory note issued to the Town of Whitby. The Town has the option of calling the principal amount in whole or in part with twelve months notice. The Town of Whitby does not anticipate calling this note before January 1, 2009.	**21,816,642**	21,816,642
	28,337,942	28,337,942

Interest on long-term debt is $2,000,000 (2006 - $2,000,000).

6. Credit facility

The Corporation requested and received an unsecured credit facility with a Canadian chartered bank and the related agreement was executed on April 8, 2002. This facility is uncommitted and repayment is due on demand. This credit facility agreement allows for Letters of Credit up to $6.9 million and provides a revolving credit facility of $2 million. As at December 31, 2007, the Corporation had utilized $5,393,461 of the credit facility to provide IESO with a letter of credit for prudential support. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. The existing credit facility can be drawn upon by either direct advances bearing interest at prime plus 0.00% or by way of letter of credit with a fee of 50 basis points per annum.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

7. Income taxes

The Corporation became obligated to make payments-in-lieu of taxes on October 1, 2001. There were no income or capital taxes in the periods prior to October 1, 2001.

The provision for income taxes under the taxes payable method for the year is $3,097,337 (2006 - $2,503,446).

Future income taxes have not been recorded in the accounts as they are expected to be reflected through future distribution revenues. As at December 31, 2007, future income tax assets (primarily related to capital assets) of $2,635,610 (2006 - $2,927,220) have not been recorded on the balance sheet. Future income tax expense of $291,610 (2006 - $161,033) has not been reflected in the income tax provision for the year ended December 31, 2007.

8. Related party transactions

The following summarizes the Corporation's related party transactions with the Town of Whitby for the years ended December 31, 2007 and December 31, 2006:

	2007	2006
		(Note 15)
	$	$
Revenue		
Energy and distribution	**2,802,712**	2,803,352
Expenses		
Interest expense	**2,000,000**	2,000,000
Property taxes	**213,888**	-
Other	**30,000**	-

The following summarizes the Corporation's related party transactions with associated companies (companies under common control) for the years ended December 31, 2007 and December 31, 2006.

	2007	2006
	$	$
Conservation Demand Management	**455,098**	339,000
Vehicle replacement	**452,010**	431,000
Capital services	**6,205,266**	5,586,000
Operation and maintenance and administrative services	**6,308,572**	5,977,000

The above noted charges are pursuant to an annual agreement with Whitby Hydro Energy Service Corporation.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

9. Financial instruments and risk management

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives.

Fair value of financial assets and liabilities

The review of all existing contracts substantiates that the Corporation does not currently have any contracts containing embedded derivatives that need to be accounted for separately using fair value.

The fair value of the Corporation's cash, accounts receivable, accounts payable and accrued liabilities and refundable consumer deposits approximate their carrying amount because of the short term maturity of these instruments.

The fair value of the Corporation's promissory notes payable to the Corporation of the Town of Whitby and due to/from related parties is not determined due to their related party nature and variable terms.

The Corporation is not exposed to significant interest rate risk as a result of its fixed rate related party debt and the short-term maturity of its monetary current assets and current liabilities.

Financial assets held by the Corporation expose it to credit risk. As at December 31, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets.

Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member's claims experience. Coverage is provided to a level of $20 million per incident.

10. Interest in limited partnership

The Corporation sold its shares in EnerConnect, a power procurement partnership under a three year staged cash payout with a $7,139 payment for 2007. Whitby Hydro Electric Corporation had a 1.587% (2006 - 1.5844%) interest in this partnership. The investment of $46,389 was expensed in the years in which it was made.

11. Future commitments

The Corporation has entered into an agreement with a service provider, which expires in 2008. The Corporation is obligated to make a payment of $12,000 under this agreement.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

12. Contingencies

(a) Legal claims

The Corporation has been named as a defendant in a legal action. No provision has been recorded in the financial statement for this potential liability as the Corporation expects that this legal action is adequately covered by its insurance.

(b) Class action of late payment charges

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.

Whitby Hydro collected total late payment penalties of $2,081,699 for the period from 1994 to 2001. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

13. Regulatory accounts

	2007	2006
		(Note 15)
	$	$
Regulatory accounts (including carrying charges)		
Regulatory accounts- Post 2004		
Government cheques rebate program	**1,223**	1,168
Retail costs variance		
Retail services	**194,253**	132,376
STR requests and processing	**(838)**	126
Retail settlement variance		
Transmission network charge	**(501,896)**	36,605
Transmission connection charge	**(585,237)**	(128,043)
Wholesale market service	**(1,434,356)**	(249,382)
Power energy cost	**148,360**	783,771
Global adjustment	**116,435**	153,119
Low voltage variance	**(64,378)**	11,631
	(2,126,434)	741,371
Regulatory accounts and approved recoveries		
Recovery of regulatory accounts	**(5,627,409)**	(3,512,988)
Unrecovered regulatory accounts prior years	**5,441,383**	5,241,448
Regulatory Accounts Hydro One charges	**400,239**	177,890
	214,213	1,906,350
Deferred payments in lieu of taxes	**(1,579,726)**	(1,516,099)
	(3,491,947)	1,131,622

The Corporation does not record regulatory assets or regulatory liabilities on its balance sheet but provides disclosure of these regulatory accounts as noted above.

Whitby Hydro Electric Corporation

Notes to the financial statements
December 31, 2007

14. Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee. The Corporation's primary guarantees subject to disclosure requirements are as follows:

(a) Indemnity has been provided to all directors and or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(b) In the normal course of business, the Corporation has entered into agreements that include indemnities in favour of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The term of these indemnities are not explicitly defined and the maximum amount of any potential reimbursements cannot be estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

15. Comparative figures

Certain prior year's comparative figures have been reclassified to conform with the current year's presentation.

Table 1-2: Pro-Forma Balance Sheet for the Year 2010

ACCOUNT DESCRIPTION	TOTAL
1050 - Current Assets	
1005-Cash	5,600,000
1100-Customer Accounts Receivable	6,500,000
1110-Other Accounts Receivable	179,312
1120-Accrued Utility Revenues	9,703,978
1130-Accumulated Provision for Uncollectible Accounts--Credit	(700,000)
1180-Prepayments	80,000
1190-Miscellaneous Current and Accrued Assets	50,000
1050 - Current Assets Total	**21,413,290**
1100 - Inventory	
1330-Plant Materials and Operating Supplies	870,000
1100 - Inventory Total	**870,000**
1200 - Other Assets and Deferred Charges	
1518-RCVARetail	54,500
1525-Miscellaneous Deferred Debits	70
1548-RCVASTR	2,144
1550-LV Variance Account	(330,593)
1555-Smart Meters Capital Variance Account	6,500,000
1556-Smart Meters OM&A Variance Account	500,000
1562-Deferred Payments in Lieu of Taxes	(1,661,563)
1563-Account 1563 - Deferred PILs Contra Account	1,661,563
1574-1588 RSVA Global Adjustment	1,540,000
1580-RSVAWMS	(103,823)
1584-RSVANW	(119,067)
1586-RSVACN	(352,293)
1588-RSVAPOWER	(280,000)
1590-Recovery of Regulatory Asset Balances	(4,735,601)
1200 - Other Assets and Deferred Charges Total	**2,675,337**
1450 - Distribution Plant	
1805-Land	245,786
1806-Land Rights	10,971
1808-Buildings and Fixtures	1,117,302
1820-Distribution Station Equipment - Normally Primary below 50 kV	18,002,014
1830-Poles, Towers and Fixtures	25,454,253
1835-Overhead Conductors and Devices	15,032,111
1840-Underground Conduit	17,513,633
1845-Underground Conductors and Devices	15,416,510
1850-Line Transformers	29,889,940
1855-Services	18,757,407
1860-Meters	5,788,165
1450 - Distribution Plant Total	**147,228,090**
1500 - General Plant	
1905-Land	182,215
1908-Buildings and Fixtures	5,640,349
1915-Office Furniture and Equipment	914,537
1920-Computer Equipment - Hardware	1,390,595
1925-Computer Software	1,696,413
1935-Stores Equipment	56,187
1940-Tools, Shop and Garage Equipment	4,284
1945-Measurement and Testing Equipment	20,903
1955-Communication Equipment	78,103
1980-System Supervisory Equipment	2,226,976
1500 - General Plant Total	**12,210,562**
1550 - Other Capital Assets	
1995-Contributions and Grants - Credit	(24,570,884)
1550 - Other Capital Assets Total	**(24,570,884)**
1600 - Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(69,022,407)
1600 - Accumulated Amortization Total	**(69,022,407)**
Net Fixed Assets	**65,845,361**
TOTAL ASSETS	**90,803,988**

ACCOUNT DESCRIPTION	TOTAL
1650 - Current Liabilities	
2205-Accounts Payable	(2,000,000)
2208-Customer Credit Balances	(800,000)
2210-Current Portion of Customer Deposits	(800,000)
2220-Miscellaneous Current and Accrued Liabilities	(500,000)
2240-Accounts Payable to Associated Companies	(200,000)
2256-Independent Market Operator Fees and Penalties Payable	(6,200,000)
1650 - Current Liabilities Total	**(10,500,000)**
1700 - Non-Current Liabilities	
2320-Other Miscellaneous Non-Current Liabilities	(60,000)
2335-Long Term Customer Deposits	(1,000,000)
2350-Future Income Tax - Non-Current	2,780,000
2405-Other Regulatory Liabilities	(11,000)
2425-Other Deferred Credits	0
1700 - Non-Current Liabilities Total	**1,709,000**
1800 - Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	(40,226,942)
1800 - Long-Term Debt Total	**(40,226,942)**
1850 - Shareholder's Equity	
3005-Common Shares Issued	(29,494,042)
3045-Unappropriated Retained Earnings	(11,748,554)
3046-Balance Transferred From Income	(3,063,450)
3049-Dividends Payable-Common Shares	2,520,000
1850 - Shareholder's Equity Total	**(41,786,046)**
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**(90,803,988)**
BALANCE SHEET TOTAL	**(0)**

Table 1-3: Pro-Forma Income Statement for the Year 2010

ACCOUNT DESCRIPTION	TOTAL
3000 - Sales of Electricity	
4006-Residential Energy Sales	(22,436,835)
4025-Street Lighting Energy Sales	(582,089)
4030-Sentinel Lighting Energy Sales	(2,776)
4035-General Energy Sales	(31,515,420)
4062-Billed WMS	(5,787,613)
4066-Billed NW	(4,442,402)
4068-Billed CN	(3,992,393)
4075-Billed-LV	(203,590)
3000 - Sales of Electricity Total	**(68,963,116)**
3050 - Revenue From Services - Distribution	
4080-Distribution Services Revenue	(20,059,013)
4082-Retail Services Revenues	(57,021)
4084-Service Transaction Requests (STR) Revenues	(719)
4090-Electric Services Incidental to Energy Sales	(143,048)
3050 - Revenue From Services - Distribution - Total	**(20,259,801)**
3100 - Other Operating Revenues	
4210-Rent from Electric Property	(133,121)
4225-Late Payment Charges	(321,000)
4235-Miscellaneous Service Revenues	(157,835)
3100 - Other Operating Revenues - Total	**(611,956)**
3150 - Other Income & Deductions	
4375-Revenues from Non-Utility Operations	(986,717)
4380-Expenses of Non-Utility Operations	944,640
4390-Miscellaneous Non-Operating Income	(25,000)
3150 - Other Income & Deductions - Total	**(67,077)**
3200 - Investment Income	
4405-Interest and Dividend Income	(9,407)
3200 - Investment Income - Total	**(9,407)**
3350 - Power Supply Expenses	
4705-Power Purchased	54,537,119
4708-Charges-WMS	4,630,090
4714-Charges-NW	4,442,402
4716-Charges-CN	3,992,393
4730-Rural Rate Assistance Expense	1,157,523
4750-Charges-LV	203,590
3350 - Power Supply Expenses Total	**68,963,116**

ACCOUNT DESCRIPTION	TOTAL
3500 - Distribution Expenses - Operations	
5005-Operation Supervision and Engineering	93,099
5010-Load Dispatching	350,806
5012-Station Buildings and Fixtures Expense	129,033
5017-Distribution Station Equipment - Operation Supplies and Expenses	41,533
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	48,705
5030-Overhead Subtransmission Feeders - Operation	29,881
5035-Overhead Distribution Transformers- Operation	23,939
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	240,400
5055-Underground Distribution Transformers - Operation	29,701
5065-Meter Expense	369,727
5075-Customer Premises - Materials and Expenses	142,492
5085-Miscellaneous Distribution Expense	470,285
5095-Overhead Distribution Lines and Feeders - Rental Paid	1,120
3500 - Distribution Expenses - Operations Total	**1,970,721**
3550 - Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	155,860
5110-Maintenance of Buildings and Fixtures - Distribution Stations	5,815
5114-Maintenance of Distribution Station Equipment	316,127
5120-Maintenance of Poles, Towers and Fixtures	75,903
5125-Maintenance of Overhead Conductors and Devices	310,822
5130-Maintenance of Overhead Services	122,149
5135-Overhead Distribution Lines and Feeders - Right of Way	131,392
5150-Maintenance of Underground Conductors and Devices	213,900
5155-Maintenance of Underground Services	280,646
5160-Maintenance of Line Transformers	219,350
5175-Maintenance of Meters	58,030
3550 - Distribution Expenses - Maintenance Total	**1,889,994**
3650 - Billing & Collecting	
5305-Supervision	35,063
5310-Meter Reading Expense	258,184
5315-Customer Billing	680,570
5320-Collecting	143,336
5330-Collection Charges	20,359
5335-Bad Debt Expense	200,000
5340-Miscellaneous Customer Accounts Expenses	814,854
3650 - Billing & Collecting - Total	**2,152,366**
3700 - Community Relations	
5415-Energy Conservation	66,000
5425-Miscellaneous Customer Service and Informational Expenses	13,572
3700 - Community Relations Total	**79,572**

ACCOUNT DESCRIPTION	TOTAL
3800 - Administrative and General Expenses	
5605-Executive Salaries and Expenses	60,170
5610-Management Salaries and Expenses	913,739
5615-General Administrative Salaries and Expenses	479,310
5620-Office Supplies and Expenses	109,760
5630-Outside Services Employed	238,880
5635-Property Insurance	37,000
5640-Injuries and Damages	88,000
5655-Regulatory Expenses	392,429
5660-General Advertising Expenses	2,240
5665-Miscellaneous General Expenses	300,240
5675-Maintenance of General Plant	231,000
5685-Independent Market Operator Fees and Penalties	40,000
3800 - Administrative and General Expenses Total	**2,892,768**

3850 - Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	4,929,391
3850 - Amortization Expense Total	**4,929,391**

3900 - Interest Expense	
6005-Interest on Long Term Debt	2,456,351
6035-Other Interest Expense	13,000
3900 - Interest Expense Total	**2,469,351**

4000 - Income Taxes	
6110-Income Taxes	1,500,627
4000 - Income Taxes Total	**1,500,627**

TOTAL INCOME STATEMENT	**(3,063,450)**

Table 1-4: Pro-Forma Balance Sheet for the Year 2009

ACCOUNT DESCRIPTION	TOTAL
1050 - Current Assets	
1005-Cash	3,400,000
1100-Customer Accounts Receivable	6,400,000
1110-Other Accounts Receivable	390,882
1120-Accrued Utility Revenues	9,657,141
1130-Accumulated Provision for Uncollectible Accounts--Credit	(700,000)
1180-Prepayments	80,000
1190-Miscellaneous Current and Accrued Assets	50,000
1050 - Current Assets Total	**19,278,023**
1100 - Inventory	
1330-Plant Materials and Operating Supplies	870,000
1100 - Inventory Total	**870,000**
1200 - Other Assets and Deferred Charges	
1518-RCVARetail	287,000
1525-Miscellaneous Deferred Debits	1,400
1548-RCVASTR	1,000
1550-LV Variance Account	(400,000)
1555-Smart Meters Capital Variance Account	600,000
1556-Smart Meters Capital OM&A	140,000
1562-Deferred Payments in Lieu of Taxes	(1,647,430)
1563-Account 1563 - Deferred PILs Contra Account	1,647,430
1574-1588 RSVA Global Adjustment	2,000,000
1580-RSVAWMS	(2,200,000)
1584-RSVANW	(1,420,000)
1586-RSVACN	(1,720,000)
1588-RSVAPOWER	(1,250,000)
1590-Recovery of Regulatory Asset Balances	(493,754)
1200 - Other Assets and Deferred Charges Total	**(4,454,354)**
1450 - Distribution Plant	
1805-Land	245,786
1806-Land Rights	10,971
1808-Buildings and Fixtures	1,117,302
1820-Distribution Station Equipment - Normally Primary below 50 kV	16,621,014
1830-Poles, Towers and Fixtures	21,458,253
1835-Overhead Conductors and Devices	13,988,111
1840-Underground Conduit	16,765,633
1845-Underground Conductors and Devices	14,800,510
1850-Line Transformers	28,394,940
1855-Services	17,727,407
1860-Meters	5,656,165
1450 - Distribution Plant Total	**136,786,090**
1500 - General Plant	
1905-Land	182,215
1908-Buildings and Fixtures	5,483,349
1915-Office Furniture and Equipment	904,537
1920-Computer Equipment - Hardware	1,304,595
1925-Computer Software	1,492,413
1935-Stores Equipment	56,187
1940-Tools, Shop and Garage Equipment	4,284
1945-Measurement and Testing Equipment	20,903
1955-Communication Equipment	78,103
1980-System Supervisory Equipment	2,146,976
1985-Sentinel Lighting Rental Units	(0)
1500 - General Plant Total	**11,673,562**
1550 - Other Capital Assets	
1995-Contributions and Grants - Credit	(21,977,884)
1550 - Other Capital Assets Total	**(21,977,884)**
1600 - Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(64,093,016)
1600 - Accumulated Amortization Total	**(64,093,016)**
Net Fixed Assets	**62,388,752**
TOTAL ASSETS	**78,082,420**

ACCOUNT DESCRIPTION	TOTAL
1650 - Current Liabilities	
2205-Accounts Payable	(1,900,000)
2208-Customer Credit Balances	(800,000)
2210-Current Portion of Customer Deposits	(800,000)
2220-Miscellaneous Current and Accrued Liabilities	(500,000)
2240-Accounts Payable to Associated Companies	(300,000)
2256-Independent Market Operator Fees and Penalties Payable	(5,800,000)
1650 - Current Liabilities Total	**(10,100,000)**
1700 - Non-Current Liabilities	
2320-Other Miscellaneous Non-Current Liabilities	(60,000)
2335-Long Term Customer Deposits	(1,000,000)
2350-Future Income Tax - Non-Current	2,730,000
2405-Other Regulatory Liabilities	(11,000)
1700 - Non-Current Liabilities Total	**1,659,000**
1800 - Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	(28,337,942)
1800 - Long-Term Debt Total	**(28,337,942)**
1850 - Shareholder's Equity	
3005-Common Shares Issued	(29,494,042)
3045-Unappropriated Retained Earnings	(11,970,974)
3046-Balance Transferred From Income	(2,238,462)
3049-Dividends Payable-Common Shares	2,400,000
1850 - Shareholder's Equity Total	**(41,303,478)**
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**(78,082,420)**
BALANCE SHEET TOTAL	**0**

Table 1-5: Pro-Forma Income Statement for the Year 2009

ACCOUNT DESCRIPTION	TOTAL
3000 - Sales of Electricity	
4006-Residential Energy Sales	(22,317,964)
4025-Street Lighting Energy Sales	(571,921)
4030-Sentinel Lighting Energy Sales	(3,114)
4035-General Energy Sales	(31,348,888)
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4062-Billed WMS	(5,706,285)
4066-Billed NW	(4,191,212)
4068-Billed CN	(4,168,576)
4075-Billed-LV	(480,388)
3000 - Sales of Electricity Total	**(68,788,347)**
3050 - Revenue From Services - Distribution	
4080-Distribution Services Revenue	(17,725,423)
4082-Retail Services Revenues	(57,121)
4084-Service Transaction Requests (STR) Revenues	(719)
4090-Electric Services Incidental to Energy Sales	(141,158)
3050 - Revenue From Services - Distribution - Total	**(17,924,420)**
3100 - Other Operating Revenues	
4210-Rent from Electric Property	(146,094)
4225-Late Payment Charges	(375,000)
4235-Miscellaneous Service Revenues	(154,835)
3100 - Other Operating Revenues - Total	**(675,929)**
3150 - Other Income & Deductions	
4375-Revenues from Non-Utility Operations	(986,717)
4380-Expenses of Non-Utility Operations	944,640
4390-Miscellaneous Non-Operating Income	(45,000)
3150 - Other Income & Deductions - Total	**(87,077)**
3200 - Investment Income	
4405-Interest and Dividend Income	11,279
3200 - Investment Income - Total	**11,279**
3350 - Power Supply Expenses	
4705-Power Purchased	54,241,887
4708-Charges-WMS	4,605,026
4714-Charges-NW	4,191,212
4716-Charges-CN	4,168,576
4730-Rural Rate Assistance Expense	1,101,259
4750-Charges-LV	480,388
3350 - Power Supply Expenses Total	**68,788,347**

ACCOUNT DESCRIPTION	TOTAL
3500 - Distribution Expenses - Operations	
5005-Operation Supervision and Engineering	85,129
5010-Load Dispatching	322,791
5012-Station Buildings and Fixtures Expense	124,860
5017-Distribution Station Equipment - Operation Supplies and Expenses	22,249
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	31,742
5030-Overhead Subtransmission Feeders - Operation	21,389
5035-Overhead Distribution Transformers- Operation	14,345
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	220,948
5055-Underground Distribution Transformers - Operation	12,746
5065-Meter Expense	400,122
5075-Customer Premises - Materials and Expenses	140,288
5085-Miscellaneous Distribution Expense	468,001
5095-Overhead Distribution Lines and Feeders - Rental Paid	1,120
3500 - Distribution Expenses - Operations Total	**1,865,730**

3550 - Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	133,176
5110-Maintenance of Buildings and Fixtures - Distribution Stations	5,820
5114-Maintenance of Distribution Station Equipment	303,762
5120-Maintenance of Poles, Towers and Fixtures	65,259
5125-Maintenance of Overhead Conductors and Devices	349,363
5130-Maintenance of Overhead Services	111,369
5135-Overhead Distribution Lines and Feeders - Right of Way	127,005
5150-Maintenance of Underground Conductors and Devices	260,128
5155-Maintenance of Underground Services	262,258
5160-Maintenance of Line Transformers	197,085
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	54,734
3550 - Distribution Expenses - Maintenance Total	**1,869,959**

3650 - Billing & Collecting	
5305-Supervision	34,003
5310-Meter Reading Expense	253,541
5315-Customer Billing	603,108
5320-Collecting	140,488
5330-Collection Charges	18,135
5335-Bad Debt Expense	200,000
5340-Miscellaneous Customer Accounts Expenses	785,283
5425-Miscellaneous Customer Service and Informational Expenses	6,801
3650 - Billing & Collecting - Total	**2,041,359**
3700 - Community Relations	
5415-Energy Conservation	66,000
3700 - Community Relations Total	**66,000**

ACCOUNT DESCRIPTION	TOTAL
3800 - Administrative and General Expenses	
5605-Executive Salaries and Expenses	79,450
5610-Management Salaries and Expenses	859,268
5615-General Administrative Salaries and Expenses	411,278
5620-Office Supplies and Expenses	106,400
5630-Outside Services Employed	214,400
5635-Property Insurance	36,000
5640-Injuries and Damages	85,000
5655-Regulatory Expenses	354,108
5660-General Advertising Expenses	2,240
5665-Miscellaneous General Expenses	296,600
5675-Maintenance of General Plant	224,000
5685-Independent Market Operator Fees and Penalties	40,000
3800 - Administrative and General Expenses Total	**2,708,744**

3850 - Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	4,582,515
3850 - Amortization Expense Total	**4,582,515**
3900 - Interest Expense	
6005-Interest on Long Term Debt	2,000,000
6035-Other Interest Expense	7,000
3900 - Interest Expense Total	**2,007,000**
4000 - Income Taxes	
6110-Income Taxes	1,296,377
4000 - Income Taxes Total	**1,296,377**

TOTAL INCOME STATEMENT	**(2,238,462)**

1 # RECONCILIATION OF REGULATORY STATEMENTS

2 ## Table 1-6: Reconciliation of Regulatory Statements to Audited Statements, 2008

	Regulatory	Audited	Difference	
Assets				
Current Assets	21,883,813	21,883,813	0	
Inventory	941,686	941,686		
Net Fixed Assets	61,600,436	62,197,767	-597,331	See note 1
Other Deferred Chargs		9,169	-9,169	See note 1
Regulatory Assets/(Liabilities)				
Smart Meters -Regulatory Asset	255,323		255,323	see note 2.d.
Regulatory Assets/(Liabilities)	-5,591,593		-5,591,593	-see note 3.
Total Regulatory Assets/Liabilities	-5,336,270	0	-5,336,270	
Total Assets	**79,089,665**	**85,032,435**	**-5,942,770**	
Liabilities				
Current Liabilities	10,870,506	10,870,506	0	
Long Term Liabilities	29,484,143	29,823,303	-339,160	see note 2.b.
Total Liabilities	40,354,649	40,693,809	-339,160	
Equity				
Common Shares	29,494,042	29,494,042	0	
Retained Earnings				
Opening Retained Earnings	9,672,162	11,590,443	-1,918,281	
Net Income- 2008	1,312,812	4,998,141	-3,685,329	
Dividends- 2008	-1,744,000	-1,744,000	0	
Closing Retained Earnings	9,240,974	14,844,584	-5,603,610	-see note 4
Total Equity	38,735,016	44,338,626	-5,603,610	
Total Liabilities and Equity	**79,089,665**	**85,032,435**	**-5,942,770**	
Net Income				
Revenue- pass through	63,151,136			
Distribution	18,013,881			
	81,165,017	85,016,298	-3,851,281	See note 5
Other Operating Revenues	694,529	941,448	-246,919	See note 5
Other Income	81,462	22,827		
Interest	7,450	277,097	-269,647	See note 5
Total other revenue	783,441	1,241,372	-457,931	
Total Revenue	81,948,458	86,257,670	-4,309,212	
Expenses				
Power Costs	63,151,136	63,774,769	-623,633	See note 5
OMA	8,206,897	8,342,844	-135,947	See note 5
Financial Expense	2,081,542	2,081,542	0	
Amortization Expense	4,401,237	4,401,237	0	
	77,840,812	78,600,392	-759,580	
Taxes	2,794,834	2,659,137	135,697	See note 5
Total Expenses	**80,635,646**	**81,259,529**	-623,883	
Net Income	1,312,812	4,998,141	-3,685,329	See note 5

Table 1-6: Reconciliation of Regulatory Statements to Audited Statements, 2008 - Continued

1. Net Fixed Asset Reconciliation:			
Smart Meter capital costs	606,500	See note 2.a.	
Land rights classfied as Deferred Charge	-9,169	Grouped under Deferred Charge	
	597,331		-597,331
2. Smart Meter Reconciliation:		GAAP Classification	
a. Costs incurred to date	606,500	Grouped under Capital WIP	
b. Revenue Collected from customers	-339,160	Grouped under Non Current Liabilities	
Total Principal	267,340		
c. Carrying charges	-12,017	Not recognized under GAAP	
d. Account 1555	255,323		255,323
3. Regulatory Assets/Liabilities(excluding Smart Meters):		GAAP Classification	
Ending Balance - 2007	-1,912,221	Regulatory Assets/(Liabilities) recognized	
Additions for 2008 - Principal	-3,415,682	in income since inception.	
Carrying charges - 2008	-269,647		
Smart Meter carrying charges for 2008-see below	5,957		
	-5,591,593		
Smart Meters:			
Ending Balance - 2007	-138,896		
Additions for 2008 - Principal	400,176		
Carrying chargs -2008	-5,957		
	255,323	See note 2	
Total Regulatory Assets/Liabilities	-5,336,270		-5,336,270
4. Equity Reconcilation:		GAAP Classification	
Total Regulatory Assets/Liabilities	-5,336,270		
Less Smart meter principal	-267,340		-5,603,610
Difference in Equity	-5,603,610	Regulatory Assets/Liabilities recognized in income since inception	
5. Net Income Reconciliation(summarized):		GAAP Classification	
2008 additions to Regulatory Assets-Principal(exclu	-3,415,682	Regulatory Assets/(Liabilities) recognized	
2008 additions to Regulatory Assets-Carrying charg	-269,647	in income since inception.	
	-3,685,329		
Net Income Reconciliation(by line item):		GAAP Classification	
Revenues			
Adjustment to commodity to RPP pricing	-592,749	Required for GAAP	
Regulatory assets/liabilities for 2008- RSVA	-2,799,528	Grouped in Income for GAAP	
Regulatory assets/liabilities for 2008- RCVA	-250	Grouped in Income for GAAP	
Recovery of Regulatory assets/liabilities for 2008	-647,038	Grouped in Income for GAAP	
RPP and Retail Service charges grouped under Othe	188,284	Reclassification - see next line item	
	-3,851,281		
RPP and Retail Service charges grouped under Othe	-188,284	Reclassification - see above.	
Carrying Charges for 2008	-269,647	Grouped in Income for GAAP	
	-4,309,212		
Power Costs			
Adjustment to commodity to RPP pricing	592,749	Required for GAAP	
Minor difference due to rounding			
Regulatory assets/liabilities for 2008 - RCVA	30,884	Grouped with power costs for GAAP	
	623,633		
OMA			
Regulatory assets/liabilities for 2008 - RCVA	250	Grouped with power costs for GAAP	
Capital taxes grouped with Administration	135,697	Grouped with administration for GAAP	
	135,947		
TAXES			
Capital taxes grouped with Administration	-135,697	Grouped with administration for GAAP	
Total difference to net income	-3,685,329		-3,685,329

Table 1-7: Reconciliation of Regulatory Statements to Audited Statements, 2007

	Regulatory	Audited	Difference	
Assets				
Current Assets	22,220,943	22,220,943		
Inventory	847,302	847,302		
Net Fixed Assets	58,506,145	58,487,808	18,337	see note 1
Other Deferrred Charges		18,337	-18,337	see note 1
Regulatory Assets/(Liabilities)				
Smart Meters -Regulatory Asset	-138,896		-138,896	see note 2
Regulatory Assets/(Liabilities)	-1,912,221		-1,912,221	see note 3
Total Regulatory Assets/Liabilities	-2,051,117	0	-2,051,117	
Total Assets	**79,523,273**	**81,574,390**	**-2,051,117**	
Liabilities				
Current Liabilities	10,923,657	10,923,657	0	
Long Term Liabilities	29,433,412	29,566,248	-132,836	see note 2
Total Liabilities	40,357,069	40,489,905	-132,836	
Equity				
Common Shares	29,494,042	29,494,042	0	
Retained Earnings				
Opening Retained Earnings	10,237,463	7,591,005	2,646,458	
Net Income- 2007	854,698	5,419,438	-4,564,740	
Dividends- 2007	-1,420,000	-1,420,000	0	
Closing Retained Earnings	9,672,161	11,590,443	-1,918,282	see note 4
Total Equity	39,166,203	41,084,485	-1,918,282	
Total Liabilities and Equity	**79,523,272**	**81,574,390**	**-2,051,118**	
	81,574,389			
Net Income				
Revenue- pass through	62,241,766			
Distribution	18,130,330			
	80,372,096	87,733,739	-7,361,643	see note 5
Other Operating Revenues	616,511	799,701	-183,190	see note 5
Other Income	46,565	46,568	-3	
Interest	292,736	325,490	-32,754	carrying charges
Total other revenue	955,812	1,171,759	-215,947	
Total Revenue	81,327,908	88,905,498	-7,577,590	
Expenses				
Power Costs	62,241,766	65,253,667	-3,011,901	see note 5
OMA	8,730,642	8,902,891	-172,249	see note 5
Financial Expense	2,103,610	2,103,610	0	
Amortization Expense	4,128,556	4,128,555	1	
	77,204,574	80,388,723	-3,184,149	
Taxes	3,268,636	3,097,337	171,299	See note 5
Total Expenses	**80,473,210**	**83,486,060**	-3,012,850	
Net Income	854,698	5,419,438	-4,564,740	See note 5

Table 1-7: Reconciliation of Regulatory Statements to Audited Statements, 2007 - Continued

1. Net Fixed Asset Reconciliation:		GAAP Classification
Land rights	18,337	Grouped under Deferred Charge
2. Smart Meter Reconciliation:		GAAP Classification
a. Costs incurred to date	75,028	Grouped under Capital WIP
b. Revenue Collected from customers	-207,864	Grouped under Non Current Liabilities
Total Principal	-132,836	
c. Carrying charges	-6,060	Not recognized under GAAP
d. Account 1555	-138,896	
3. Regulatory Assets/Liabilities(Excluding Smart Meters		GAAP Classification
Ending Balance -2006	2,647,152	Regulatory Assets/(Liabilities) recognized
Additions for 2007 - Principal	-4,531,985	in income since inception.
Carrying charges -2007	-32,754	
Less Smart Meter carrying charges for 2007- see below	5,365	
	-1,912,222	
Smart Meters		
Ending Balance -2006	-82,911	
Additions for 2007 - Principal	-50,620	
Carrying chargs -2007	-5,365	
	-138,896	See note 2
Total Regulatory Assets/Liabilities	**-2,051,118**	
4. Equity Reconcilation		GAAP Classification
Total Regulatory Assets/Liabilities	-2,051,118	
Less Smart meter principal	132,836	
Difference in Equity	**-1,918,282**	Regulatory Assets/Liabilities recognized in income since inception.
5. Net Income Reconciliation(summarized):		GAAP Classification
2007 additions to Regulatory Assets-Principal(excluding Smart Meters)	-4,531,985	Regulatory Assets/(Liabilities) recognized
2007 additions to Regulatory Assets-Carrying charges	-32,754	in income since inception.
	-4,564,739	
Net Income Reconciliation(by line item):		GAAP Classification
Revenues		
Adjustment to commodity for RPP pricing	-2,745,416	Required for GAAP
Regulatory assets/liabilities for 2007 -RSVA	-2,878,942	Grouped in Income for GAAP
Regulatory assets/liabilities for 2007 -RCVA	-950	Grouped in Income for GAAP
Recovery of Regulatory Assets	-1,919,528	Grouped in Income for GAAP
RPP and Retail Service charges grouped under Other Income	183,193	Reclassification -see next line item
	-7,361,643	
RPP and Retail Service charges grouped under Other Income	-183,193	Reclassification -see above.
Carrying Charges for 2007	-32,754	Grouped in Income for GAAP
	-7,577,590	
Power Costs		
Adjustment to commodity for RPP pricing	2,745,416	Required for GAAP
HONI regulatory charges	212,525	Grouped with power costs for GAAP
Regulatory assets/liabilities for 2007 -RCVA	53,960	Grouped with power costs for GAAP
	3,011,901	
OMA		
Regulatory assets/liabilities for 2007 -RCVA	950	Grouped with power costs for GAAP
Capital taxes grouped with Administration	171,299	Grouped with administration for GAAP
	172,249	
TAXES		
Capital taxes grouped with Administration	**-171,299**	Grouped with administration for GAAP
Total difference to net	**-4,564,739**	

MATERIALITY THRESHOLD

The materiality threshold used throughout this application has been prescribed by the Board's Filing Requirements as 0.5% of distribution revenue requirement for those distributors with a revenue requirement greater than $10 million and less than or equal to $200 million. Whitby Hydro has based its materiality threshold on the proposed 2010 revenue requirement of $20,747,189 and adopted a variance analysis threshold of $103,736.

EXHIBIT 2
RATE BASE

CAPITAL ASSET MANAGEMENT

BACKGROUND

Whitby Hydro was established in 1903 as Public Utilities Commission providing water and electricity distribution services to consumers in the Town of Whitby. In 1974, responsibility for water distribution services was transferred to the Region of Durham.

Today, Whitby Hydro distributes electricity to almost 40,000 residential and commercial customers within its regulated service area. The company's electrical distribution assets are key to providing reliable, safe electricity to its customers. Since the electrical infrastructure is expanded and updated on an annual basis, the age of the distribution assets range from very recent acquisitions to those which date back as far as 55 years. Whitby Hydro receives electricity at 44,000 volts and steps the power down to 13,800 and 4,160 volts for distribution. To efficiently manage its system, Whitby Hydro maintains 27 substation transformers and 1030 kilometres of overhead and underground subtransmission and distribution lines.

Whitby Hydro's asset planning process has been in place for many years and is driven by its corporate mandate to provide safe, reliable electricity and cost-effective distribution services to it customers without impairing its ability to respond efficiently to on-going customer growth and comply with evolving statutory and regulatory requirements.

HISTORICAL CAPITAL EXPENDITURES

Whitby Hydro has experienced extreme growth nearly doubling its customer base (49%) over the past 9 years (2000-2008). The growth rate over the rate rebasing period (2004-2010) continues at a substantial rate but appears to be easing off due to economic conditions. The growth rate for 1999 to 2010 is forecast to be 52.1%.

Since 2002, Whitby Hydro's distribution system has been expanded to meet the needs of a growing customer base driven by development in the GTA. To meet the electrical needs of this high level of growth, Whitby Hydro had to increase its distribution station transformer count by 125% from 12 to 27 and extend its overhead and underground distribution circuits by 131 kilometers or 14.6%. It was also necessary to increase its distribution transformer numbers by 14.8%, adding 679 new units.

Table 2-1: System Expansion – OEB PBR Filings

		2002	2003	2004	2005	2006	2007	2008	2009
Municipal Substation Transformers									
Opening Balance	12								
MS 12		1							
MS 13			1						
MS 14				3					
MS 15					3				
MS 10B						1			
MS 6							1		
MS 7								3	
MS 2									2
YTD Additions		13	14	17	20	21	22	25	27
YTD % Change		8.3%	16.7%	41.7%	66.7%	75.0%	83.3%	108.3%	125.0%

	2002	2003	2004	2005	2006	2007	2008	Total
Kilometers of Line								
Overhead	456	463	472	475	476	491	495	
Underground	443	465	484	505	520	530	535	
Total	**899**	**928**	**956**	**980**	**996**	**1,021**	**1,030**	
		29	28	24	16	25	9	131
		3.3%	3.0%	2.5%	1.6%	2.5%	0.9%	14.6%
Transformers	4,577	4,765	4,871	5,024	5,169	5,222	5,256	
		188	106	153	145	53	34	679
		4.1%	2.2%	3.1%	2.9%	1.0%	0.7%	14.8%

Table 2-2: System Demand/Load Growth

	2002	2003	2004	2005	2006	2007	2008	Total
Customers	31,237	33,371	35,146	36,487	37,649	38,279	39,226	
		2,134	1,775	1,341	1,162	630	947	7,989
		6.8%	5.3%	3.8%	3.2%	1.7%	2.5%	25.6%
MWH	780,336	792,492	825,196	911,869	897,193	911,212	897,674	
		12,156	32,704	86,673	-14,676	14,019	-13,538	117,338
		1.6%	4.1%	10.5%	-1.6%	1.6%	-1.5%	15.0%
MVA	168	200	165	209	220	211	187	
		32	-35	44	11	-10	-23	19
		19.1%	-17.5%	26.7%	5.4%	-4.4%	-11.1%	11.5%
Average Use	2,082	1,979	1,957	2,083	1,986	1,984	1,907	
		-103	-22	126	-97	-2	-77	-175
		-4.9%	-1.1%	6.4%	-4.6%	-0.1%	-3.9%	-8.4%
Average VA	5,372	5,990	4,695	5,728	5,851	5,499	4,770	
		618	-1,296	1,033	123	-352	-729	-602
		11.5%	-21.6%	22.0%	2.2%	-6.0%	-13.3%	-11.2%

Load growth has paralleled customer growth as demonstrated in the Table 2-2. Over the 6-year period from 2002 to 2008, system peak demand and wholesale MWH have increased by 11.5% and 15.0% respectively while customer growth has increased by 25.6% over the same period.

ASSET PLANNING PROCESS OVERVIEW

Whitby Hydro has an asset planning process which has serviced the utility and its customers well for many years. However, given the increasing complexity of managing a rapidly expanding distribution system and the potential for improved efficiencies recognized by the Board, Whitby Hydro is assessing its asset and maintenance processes and plans to adopt a more formal planning approach and update its process where there are cost-effective opportunities to improve efficiency. During the transition, Whitby Hydro will continue to meet its core objectives of providing safe, reliable power while addressing customer growth and its regulatory and legal requirements.

The asset planning process has allowed Whitby Hydro to prioritize the needs of its system expansion to ensure that the distribution system is in a position to respond to the needs of its existing and future customers.

Asset planning meetings are held on a bi-monthly basis with a committee comprised of the President and CEO, the Vice President and Senior Management from Engineering and Operations.

The Asset Management and Planning ("AMP") committee's role is to develop and implement electric distribution system additions and upgrades necessary to meet the core strategy in serving customer needs cost-effectively.

Through the bi-monthly asset planning process, the committee reviews and implements the following:

- Engineering standards, system operating criteria and good utility practices necessary to design and operate an integrated electrical distribution system in compliance with OEB codes and statutory regulations.
- Review and implement changes and upgrades of the existing distribution system to maintain reliability.
- Monitor load growth on a feeder by feeder basis in order to design and implement system expansions systematically.
- Life cycle cost assessment and retirement of system assets as required.
- Contingency planning for equipment failure and resumption of service.
- Operating procedures, preventive maintenance programs, field inspections and system automation are reviewed to ensure that the assets are operated and maintained to achieve a favourable economic balance between maintenance and replacement.

ANNUAL BUDGET PROCESS

In addition to its on-going asset management responsibilities, the AMP committee produces a revolving three year capital and operating budget that meets the growing needs of its distribution system in order that Whitby Hydro can achieve its core mandate.

Information is obtained from the Town of Whitby, Region of Durham, Ministry of Transportation, other utilities and developers, along with historical performance data and current records to identify and prioritize capital projects. Each department head is responsible for capital expenditure budgeting in his or her designated area. The President reviews and approves each department head's budget and submits the approved amounts to the Treasurer for compilation into a total budget. The President, Vice President and Treasurer review the budget and determine which projects will proceed and when, in order to ensure an appropriate annual spending level.

The capital projects are prioritized based on projected load growth, required road relocation work and non-discretionary upgrades of existing electrical plant in determining timing of the budgeted projects. This approach ensures that capital expenditure levels are relatively even on an annual basis and the system meets the core operating objectives.

Based on input from the budget review and project selection process, a three year capital budget is prepared by management and approved by the Whitby Hydro's Board before the start of each fiscal year. This same three year capital budget is reviewed again in June and December and is presented to Whitby Hydro's Board for approval

ASSET MANAGEMENT PLAN DEVELOPMENT

While Whitby Hydro's current asset planning process has served the utility well for many years, it is recognized that a more robust asset management plan will need to be developed to address the increased system complexity. There will be a need to co-ordinate the requirements of planned new investments, life cycle replacements and planned maintenance programs relying on enhanced data management and more structured asset condition assessments.

As noted in its March 10, 2009 report to the Ontario Energy Board, Review of Asset Management Practices in the Ontario Electric Distribution Sector, KPMG recognized that of those 21 utilities surveyed, all of the asset management practices used by these utilities were at the expected level of maturity with a number of them in a leading position in some areas. KPMG also concluded that the manner in which utilities apply asset management will vary by utility, with larger utilities generally requiring more formalized processes.

Over the next four year period Whitby Hydro is committed to developing a more formal approach to asset management, building on the effectiveness of its current asset management process. Whitby Hydro recognizes that this more formalized process must be cost effective, practical and suited to the size of Whitby Hydro so as not to unduly burden its customers with unnecessary costs.

In 2009, the upgrade of Whitby Hydro's GIS system will provide additional functionality to enhance the company's record keeping capabilities. The GIS system is the key resource to facilitate the tracking and recording of asset condition, age and maintenance performed.

Whitby Hydro plans to review the existing asset condition data currently held in the GIS system and develop an action plan to collect, assess and manage asset condition. This data and the enhanced recording processes will form the basis of the asset management plan. Data is currently kept in the GIS system on all of Whitby Hydro's main assets based on the results of the annual asset inspections, maintenance programs and capital program updates.

Using the KPMG report as a guide, an asset management plan will be developed to suit the needs of Whitby Hydro's customers with the main objective of meeting the key practices identified in the KPMG report in a practical cost effective manner.

While investments in assets will continue to be categorized to address the growth, reliability, and regulatory requirements, the asset management plan will need to be flexible to accommodate future requirements such as smart grid and the Green Energy Act initiatives.

SYSTEM PERFORMANCE

Whitby Hydro has always acknowledged the importance of managing its distribution system efficiently to ensure a high level of reliability. Given the composition of Whitby Hydro's manufacturing customer base and its need to operate with 'just-in-time' delivery to the automotive industry, it is critical for Whitby Hydro to maintain a dependable distribution plant.

With respect to system reliability, Whitby Hydro had concerns in the past regarding the impacts of supply related failures on these measurements. The OEB has in recent years, acknowledged this concern and since 2007, requested that distributors report these measurements both including and excluding supply related failures. This additional information gives preferred comparisons, as they allow those analyzing the results to measure indices which are more reflective of the reliability of the distributor's system and gives improved comparability for those distributors that are embedded or partially embedded (like Whitby Hydro). From 2006 to 2008, Whitby Hydro has maintained system reliability within the prior 3 years historical data on a consistent basis.

RELIABILITY STATISTICS

YEAR	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
	Includes Failure of Supply			Excludes Failure of Supply		
2006	0.786	0.579	1.359	N/A	N/A	N/A
2007	0.829	1.051	0.79	0.45	0.79	0.57
2008	0.242	0.428	0.566	0.24	0.43	0.57

SAIDI is the average forced sustained interruption duration per customer served per year (measured in hours). The calculation is "Total Customer Hours of Interruptions" divided by "Total Number of Customers".

SAIFI is the average number of forced sustained interruptions experienced per customer served per year (measured in outages). The calculation is the "Total Customer Interruptions" divided by "Total Number of Customers".

CAIDI is the average forced sustained interruption duration experienced by interrupted customers per year (measured in hours). The calculation is SAIDI divided by SAIFI.

Whitby Hydro continues to review outage causes to help focus the asset management processes and assess the effectiveness of planned maintenance programs to ensure the high level of system reliability required by customers.

Whitby Hydro's reliability statistics compare very favourable against the majority of utilities in Ontario (2 to 3.5 times better) and serve as a testament to the high level of attention that is given to the asset planning process and maintenance programs which help ensure our core strategies of distribution system performance are met. For the records that are publicly available, in 2007 Whitby Hydro ranked in the top 20 of 84 utilities for reliability statistics. *

** Sourced from the 2007 Yearbook of Electricity Distributors posted on the Board website*

The table below indicates that Whitby Hydro's reliability is significantly better than the average for the 84 utilities in the 2007 study.

	SAIDI	SAIFI	CAIDI
Whitby Hydro Electric Corporation	0.83	1.05	0.79
Average	2.92	2.26	2.21
Comparison (avg rating/WH's rating)	3.52	2.15	2.80

MAINTENANCE PROGRAMS

Whitby Hydro has an annual maintenance plan that is consistent with good utility practice and meets the maintenance and inspection requirements of the Board's Distribution System Code. The plan includes the following programs:

Wood Pole Testing and Replacement - Each year 1,000 distribution poles of Whitby Hydro's wood pole population are inspected and tested. At the same time an asset condition assessment is undertaken and recorded in the GIS system. Those poles that are deemed to require immediate remedial action are scheduled to be replaced or upgraded as soon as practical. Other poles are budgeted for replacement at a later date as determined by the assessment.

Insulator Washing – Overhead subtransmission and distribution circuits undergo an annual insulator washing to ensure that environmental contamination is kept in check. Visual inspection of the overhead assets is also undertaken at this time and immediate concerns are corrected proactively.

Infrared Thermography Overhead Distribution Systems and Substations – Annually, a thermography maintenance check is undertaken on all overhead distribution system and substation plant is tested semi annually.

Cleaning of Switching Cubicles (dry – ice cleaning) – On an annual basis, 25% of distribution voltage switching cubicles are dry ice cleaned to assist in prolonging the useful operating life of the equipment. An asset assessment is undertaken during the cleaning and inspection process and corrective action is taken as necessary.

Substation Maintenance – Bi-annually, distribution substations undergo a thorough inspection and asset assessment. Transformer oil analysis is undertaken annually on all station power transformers. Transformers that display less than ideal results are tested more regularly to ensure that the equipment continues to operate at an acceptable performance level. Corrective action is taken as required and less urgent asset maintenance issues are included in future budgets.

Tree Trimming – Given the extent of Whitby Hydro's overhead distribution assets and its urban/rural mix of distribution services, tree trimming is undertaken on a 3 year rotation over the company's total service area.

Load Interrupter Switch Maintenance – Overhead 44kV subtransmission and 13.8kV distribution system load interrupter switches are maintained on a 4 year inspection rotation. Corrective action is taken as required and less urgent asset maintenance issues are addressed in future years budgets.

Results of the maintenance programs and asset assessments are tracked in the GIS system and used to assist in assessing the need for replacement of assets during the annual budget process.

GREEN ENERGY AND GREEN ECONOMY ACT

On June 16, 2009, the Board issued the "Guidelines: Deemed Conditions of Licence: Distribution System Planning" (G-2009-0087). In this Guideline, the Board sets out a regulatory framework which covers accounting, funding, and planning for electric distribution system investments to accommodate the connection of renewable energy generation facilities and/or development of a smart grid, as related to the *Green Energy and Green Economy Act, 2009* ("GEGEA").

At this time Whitby Hydro is reviewing any needs for system investments and other expenditures to both accommodate the addition of renewable generation to its distribution, as well as administrative support required to assist customers with participation in the OPA's FIT and micro FIT programs. Whitby Hydro is also reviewing projects that will ultimately be included into its smart grid development plan, but will not complete these plans until the legislative and regulatory framework related to the GEGEA has been defined.

Whitby Hydro is not including any costs related to the GEGEA in this application. Whitby Hydro will continue to review and monitor activities related to the GEGEA, and anticipates that once further direction has been provided it will complete a Distribution System Plan related to GEGEA and request a specific funding adder at that time.

CAPITAL SPENDING CATEGORIES

Under Whitby Hydro's current asset planning process, capital spending is assessed using twelve (12) spending categories

- ***Customer Demand*** – These are non-discretionary investments required to connect new customer service lines in order to meet Whitby Hydro's distribution licence obligations.

- ***Reliability –*** This asset category relates to work required to ensure that the distribution system provides reliable power through planned and unplanned re-investment in existing assets.

- ***Regulatory*** – This category relates to non-discretionary work that must be undertaken to ensure that Whitby Hydro is in compliance with OEB codes and statutory regulations. It includes capital spending required as a result of municipal road relocations and safety requirements. Given the budget timing differences between Whitby Hydro and the numerous road authorities, estimates must be used for capital expenditures that could be experienced on an annual basis.

- ***Subdivision Development*** – This spending category relates to the installation and connection of new underground residential subdivisions by developers. Costs of installation and connection are shared between Whitby Hydro and the developer as outlined in the Distribution System Code using the Board's economic evaluation model. These non-discretionary costs are driven by customer growth.

- ***Commercial Servicing -*** This category is related to the servicing of new commercial customers that are required to be connected to Whitby Hydro's distribution system. It includes the supply and installation of necessary conductors, transformation and other ancillary equipment to provide electric service to the customer. The expenditures for this work are fully recovered from the customer.

- ***SCADA*** – This category is related to the installation and upgrading of Whitby Hydro's system control and the data acquisition systems in place at Hydro One transformer stations and Whitby Hydro's distribution stations.

- ***Metering*** – This non-discretionary work relates to the installation of new single phase and three phase meters for new customers as well as costs related to wholesale metering.

- ***Computer Hardware*** – This category relates to computer hardware required for Whitby Hydro's information systems such as GIS, finance and customer billing.

- ***Computer Software*** - This category relates to computer software required for Whitby Hydro's information systems such as GIS, finance and customer billing.

- ***Building*** – This category relates to those capital asset expenditures for Whitby Hydro's building.

- ***Office Equipment & Tools*** – This category relates to general office equipment and tools used in operations.

- ***Land*** – This category relates to land purchases required for the placement of new distribution station assets.

As shown in Table 2-3, Whitby Hydro has maintained a capital expenditure level close to its 5 year historical average of $6.4 million with the exception of the 2005 spending which was $2 million below the average and 2010 which is projected to be $2 million above the average.

Lower spending in 2005 represented a deferral of customer demand projects to 2006. Projects in 2004 included distribution station work and overhead distribution assets in conjunction with the new Whitby transformer station. Additional distribution stations to match customer demand were not required in 2005. The addition of a distribution station and associated distribution system assets as well as expenditures related to the Whitby transformer station resulted in 2006 expenditures more in line with the 5 year historic average.

The main drivers of capital spending in the test year are reliability which is $1.6 million above the 5 year historic average, regulatory which is $2.0 million above the 5 year historic average and subdivision development which is $0.3 million above the 5 year historic average. The increase in the reliability category can be attributed to the replacement of a distribution station for voltage conversion and underground cable rehabilitation forecast to be completed in addition to the regular reliability projects that are undertaken on an annual basis. The substantial increase in the regulatory category can be attributed to the Ministry of Transportation undertaking to widen HWY # 7 from 2 to 4 lanes necessitating a major relocation of existing overhead 44kV subtransmission and 13.8kV distribution infrastructure. The increase in subdivision activity is directly related to the capitalization of secondary service conductors as outlined later in a separate section of this Exhibit.

These higher than normal expenditures are offset partially by the spending in customer demand which is $2.0 million below the 5 year historic average. The reduced spending can be attributed to the fact that there is no requirement for new distribution station capacity in 2010 due to reduced residential and commercial development within the service area.

To the extent possible within its capital and fiscal planning, Whitby Hydro plans its capital expenditures to maintain a stable level of investment. This is best demonstrated by the increase in reliability in the bridge and test years when capital investment for customer demand was considerably below average.

Table 2-3: Net Capital Additions by Category for 2004-2012

Investment Category	2004	2005	2006	2007	2008	2009	2010	2011	2012
Customer Demand	3,095,000	1,892,000	3,408,000	3,162,000	3,919,000	64,000	1,124,000	1,031,000	956,000
Reliability	1,603,000	1,066,000	1,857,000	2,668,000	1,576,000	4,324,000	3,409,000	2,877,000	2,675,000
Regulatory	41,000	301,000	39,000	151,000	758,000	366,000	2,305,000	1,457,000	2,635,000
Subdivision Development	736,000	669,000	544,000	344,000	501,000	163,000	892,000	255,000	270,000
SCADA	268,000	214,000	170,000	95,000	39,000	41,000	80,000	82,000	84,000
Meters	706,000	305,000	181,000	154,000	298,000	120,000	132,000	95,000	122,000
Computer Hardware	80,000	25,000	41,000	101,000	154,000	95,000	86,000	65,000	65,000
Computer Software	53,000	44,000	182,000	88,000	228,000	185,000	204,000	106,000	107,000
Buildings						15,000	157,000	52,000	52,000
Office Equipment & Tools	25,000	65,000	37,000	38,000	31,000	10,000	20,000	20,000	10,000
Land	35,000	7,000	11,000					150,000	
	6,642,000	**4,588,000**	**6,470,000**	**6,801,000**	**7,504,000**	**5,383,000**	**8,409,000**	**6,190,000**	**6,976,000**

CAPITAL EXPENDITURES BY PROJECT

FOR THE YEAR 2004

Whitby Hydro's net capital expenditures in 2004 were $6,642,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment.

Table 2-4: 2004 Capital Additions

2004 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	3,095,000		3,095,000
Reliability	1,603,000		1,603,000
Regulatory	75,000	34,000	41,000
Subdivision Development	2,785,000	2,049,000	736,000
Commercial Services	328,000	328,000	0
SCADA	268,000		268,000
Meters	706,000		706,000
Computer Hardware	80,000		80,000
Computer Software	53,000		53,000
Office Equipment & Tools	25,000		25,000
Land	35,000		35,000
Total Gross Expenditures	**9,053,000**	**2,411,000**	**6,642,000**

CUSTOMER DEMAND:

Distribution Station MS # 14 - $839,000

This project required the installation of 3 – 6/8 MVA 44/13.8kV power transformers and station site and costs include site civil work to add system capacity to service new growth in the area of Conlin Road and Thickson Road north of the Brooklin area.

New 40M27 44 kV Feeder from Whitby T.S. on Hall's Rd. to M.S. #10 on Garden St. - $1,369,000

This project required the construction of a new 44kV pole line from Whitby TS to Distribution Station MS # 10 located at Halls Road and Garden Street to allow the utilization of capacity from the new Whitby transformer station to service load growth in the area.

New 13.8 kV Feeder in conjunction with 44kV feeder from Whitby T.S. on Hall's Rd. to M.S. 10 on Garden St. - $234,000

This project is related to new 44kV pole line construction noted above to allow capacity from municipal station M.S. #10 to supply new load growth in the area.

Rebuild 13.8kV Pole Line on Queen Street (Brooklin) - $110,000

The project included the rebuilding of a 13.8kV distribution pole line on Queen Street in Brooklin to allow service to a new subdivision in the area. New secondary conductor and right sizing of overhead distribution transformers was also undertaken in conjunction with this project.

Rebuild 13.8kV Pole Line on Ferguson Ave from Winchester Road to Vipond Street (Brooklin)

- $105,000

The project included the rebuilding of a 13.8kV distribution pole line on Ferguson Ave in Brooklin to allow service to a new subdivision in the area. New secondary conductor and right sizing of overhead distribution transformers was also undertaken in conjunction with this project.

Various Customer Demand Projects - $438,000

There were eleven (11) separate projects that were undertaken in various locations throughout the service area in 2004 which individual costs were under the materiality threshold. These projects were related to conductor upgrades and line extensions to service new load growth.

RELIABILITY PROJECTS:

Distribution Station MS # 6 - $167,000

This project involved the replacement of the 13.8kV underground feeder cable out of the distribution station M.S. #6 located on Rossland Road East and the re-gasketing of the 12/16/20 MVA 44/13.8kV power transformer. This project was undertaken as the result of the evaluation of several criteria including age, asset condition, safety and reliability. This distribution station was originally installed in 1970

Distribution Station MS # 8 - $211,000

This project required the refurbishment of a 12/16/20 MVA 44/13.8kV power transformer at M.S. #8 located on Rossland Road West. This work was undertaken as a result of the evaluation of several criteria including age, asset condition, safety and reliability. This distribution station was originally installed in 1976. Given that the work began late in the year, the 2004 cost only represents a portion of the overall project and the balance is reflected in the 2005 project costs. The power transformer was sent out for repairs and placed in inventory as a spare unit.

Baldwin Street- Upgrade poles and conductor (North St. to Columbus Rd. - Brooklin Central) - $177,000

This project entailed the upgrade of an existing 13.8kV distribution system pole line, poles and conductor as a result of the evaluation of criteria including age, condition, safety and reliability. Replacement of secondary conductor and right sizing of overhead distribution transformers was also undertaken in conjunction with the project.

Byron Street (M.S. #1, M.S. #4, M.S. # 10 feeder fortifications, voltage conversion) - $128,000

This project is related to the upgrading of a portion of aging overhead distribution system and included increasing conductor size and voltage conversion from 4kV to 13.8kV on distribution feeders to allow for increased reliability. Replacement of secondary conductor and right sizing of overhead distribution transformers was also undertaken in conjunction with this project.

Rehabilitate Underground Michael Blvd Subdivision (Phase 1 of 4) - $296,000

This project is related to the upgrading of underground 15kV distribution system cable and the replacement of pole transformers to pad mounted transformers in a residential subdivision based on the evaluation of several criteria including age, cable failures and to provide increased reliability. The original cables were installed in 1973.

Miscellaneous System Improvements - $335,000

These include various system improvement projects undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system faulted circuit indicators, replacement of pad mounted 15kV switchgear, various overhead and underground secondary service cable replacements and overhead and underground distribution transformer replacements. System improvements projects were undertaken based on the evaluation of several criteria including age, asset condition, safety and reliability.

Various Reliability Projects - $289,000

There were three separate projects which individual costs were under the materiality threshold which were undertaken throughout the service area in 2004. These projects were related to upgrades of distribution lines and station equipment based on the evaluation of several criteria including age, asset condition, safety and reliability.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $736,000

In 2004, residential subdivision activity resulted in the connection of 1,653 residential lots. Costs were shared with the developers in accordance with the OEB's Distribution System Code economic evaluation model which resulted in the net addition of capital of $736,000.

SCADA:

Various SCADA Projects - $268,000

SCADA projects in 2004 were undertaken to allow supervisory control and feeder monitoring at 3 of Whitby Hydro's distribution transformer stations (M.S. #4, 6 and 8) to enable station monitoring.

METERS:

Upgrade of Wholesale Metering - $482,000

This project included the upgrading of wholesale metering to keep Whitby Hydro in compliance with IESO market rules.

Various Metering Work - $224,000

These costs relate to the installation of single phase and three phase meters in connection with new customers and various meter upgrades over the course of 2004.

FOR THE YEAR 2005

Whitby Hydro's net capital expenditures in 2005 were $4,588,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment.

Table 2-5: 2005 Capital Additions

2005 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	1,892,000		1,892,000
Reliability	1,066,000		1,066,000
Regulatory	422,000	121,000	301,000
Subdivision Development	2,913,000	2,244,000	669,000
Commercial Services	642,000	642,000	0
SCADA	214,000		214,000
Meters	305,000		305,000
Computer Hardware	25,000		25,000
Computer Software	44,000		44,000
Office Equipment & Tools	65,000		65,000
Land	7,000		7,000
Total	**7,595,000**	**3,007,000**	**4,588,000**

CUSTOMER DEMAND:

Distribution Station M.S. # 14 - $339,000

This project is related to completion of the 3-6/8 MVA 44/13.8kV distribution station that was started in 2004 to provide additional capacity to meet customer growth in the area of Conlin Road and Thickson Road, north of Brooklin.

Extend 3 Phase Feeder on Vipond Road from Ferguson Avenue to Price Street - $160,000

This project entailed extending a 13.8kV distribution circuit on Vipond Road to service new load growth in the area.

Upgrade existing conduction on Thickson Road South from Dundas Street to M.S. 7 - $416,000

This project was undertaken to increase the capacity of a 1 - 44kV subtransmission circuit and 1 - 13.8kV distribution circuit by increasing conductor size in order to service new load growth in the area.

Install 1 - 3 phase 13.8kV circuit on existing poles on Thickson Rd. North from Rossland Road to Taunton Road - $153,000

This project included the installation of a new 13.8kV circuit on an existing pole line on Thickson Rd to service new load growth in the area.

Install 1 - 3 phase 13.8kV circuit on existing poles on Brock Street North from Rossland Road to Taunton Road - $105,000

This project included the installation of a new 13.8kV circuit on an existing pole line on Brock Street from Rossland Road to Taunton Road to service new load growth in the area.

15 kV U/G primary cable and switch gear replacement on Tricont Drive - $158,000

This project is related to the extension of underground 15kV cable in a commercial industrial subdivision to service new load growth in the area.

Various Customer Demand Projects -$561,000

This includes ten separate 44kV subtransmission and 13.8 kV distribution projects that were undertaken in various locations throughout the service area in 2005. These projects were related to conductor upgrades and line extensions to service new load growth and were all below the materiality threshold.

RELIABILITY PROJECTS:

Distribution Station M.S. # 9 - $131,000

This project entailed the refurbishing of a 12/16/20 MVA 44/13.8kV power transformer undertaken based on the evaluation of several criteria including age, asset condition, safety and reliability. The power transformer was originally installed in 1988.

Miscellaneous System Improvements - $320,000

These are various system improvement projects undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system faulted circuit indicators, replacement of pad mounted 15kV switchgear, various overhead and underground secondary service cable replacements and overhead and underground distribution transformer replacements. System improvement projects were undertaken based on the evaluation of several criteria including age, asset condition, safety and reliability.

Various Reliability Projects - $615,000

There were twenty three separate projects undertaken throughout the service area in 2005, of which individual costs were under the materiality threshold. These projects were related to upgrades of distribution lines and station equipment based on the evaluation of several criteria including age, asset condition, safety and reliability.

REGULATORY PROJECTS:

Taunton Road West Widening - $143,000

This project required a portion of 44kV subtransmission and 13.8kV distribution pole line to be relocated as a result of the Regional Municipality of Durham's plan to widen a portion of Taunton Road. A portion of the costs were recovered from the Region of Durham in 2006 resulting in a net expenditure of $143,000.

Various Regulatory Projects - $158,000

There were thirteen small projects related to road relocation works undertaken by the road authorities within Whitby Hydro's service area which resulted in net expenditures of $158,000 after cost recovery from the various road authorities.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $669,000

In 2005, residential subdivision activity resulted in the connection of 1,331 residential lots. Costs were shared with the developers in accordance with the OEB's Distribution System Code economic evaluation model which resulted in the net addition of capital as noted.

SCADA:

Various SCADA Projects - $214,000

SCADA projects in 2005 were undertaken to allow supervisory control and feeder monitoring at three (3) of Whitby Hydro's distribution transformer stations (M.S. #10, 11 and 14) to enable station monitoring.

METERS:

Upgrade of Wholesale Metering - $140,000

This project included the upgrading of wholesale metering to keep Whitby Hydro in compliance with IESO market rules.

Various Metering Work - $165,000

These costs relate to the installation of single phase and three phase meters in connection with new customers and various meter upgrades.

FOR THE YEAR 2006

Whitby Hydro's net capital expenditures in 2006 were $6,470,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment.

Table 2-6: 2006 Capital Additions

2006 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	3,408,000		3,408,000
Reliability	1,857,000		1,857,000
Regulatory	200,000	161,000	39,000
Subdivision Development	2,513,000	1,969,000	544,000
Commercial Services	165,000	165,000	0
SCADA	170,000		170,000
Meters	181,000		181,000
Computer Hardware	41,000		41,000
Computer Software	182,000		182,000
Office Equipment & Tools	37,000		37,000
Land	11,000		11,000
Total	**8,765,000**	**2,295,000**	**6,470,000**

<u>CUSTOMER DEMAND:</u>

Distribution Station M.S. # 15 - $1,267,000

This project included the installation of a new 3-6/8 MVA 44/13.8kV substation to supply new load growth in the area of Brock Street and Taunton Road.

Egress of 4 - 44kV Feeders (New Whitby T.S.) - from property line to riser pole locations - $558,000

This project included the installation of underground 44kV subtransmission cable and associated duct banks from the Hydro One owned Whitby transformer station to riser poles located on Halls Road. This work was undertaken to supply new load growth in the Whitby Hydro service area.

New Pole Line on Conlin Road west to Anderson, south to Solmar Ave. - $370,000

This project includes the construction of a new 13.8kV pole line on Conlin Road and Anderson Street to utilize a new 13.8kV feeder from Municipal Station M.S. #14 to service load growth in the area.

Rebuild existing pole line on west side of Baldwin Street from M.S. 9 to Winchester Road - $628,000

This project included the upgrade and installation of existing and new 13.8kV distribution feeders providing additional pole height to accommodate a future 44kV subtransmission feeder on Baldwin Street from distribution station M.S. #9 to Winchester Road to accommodate load growth in the area.

Purchase of 44kV Feeder from Hydro One - $145,000

A 44kV feeder was purchased from Hydro One at the Whitby TS to provide additional capacity for load growth in the area.

Various Customer Demand Projects - $440,000

There were fourteen (14) separate 44kV subtransmission and 13.8 kV distribution projects undertaken in various locations throughout the service area in 2006. These projects were related to overhead line extensions and additions to supply new load and all individual projects were under the materiality threshold.

RELIABILITY PROJECTS:

Distribution Station M.S. 8 - Refurbish 12/16/20 MVA 44kV/13.8kV Power Transformer - $438,000

This project included the refurbishment of a 12/16/20 MVA power transformer that had failed and was removed from service. The refurbished transformer will be kept in stock and put back into service at a future date.

Rebuild Overheads - Reynolds St. & Brooklin areas - $160,000

This project included the upgrading of overhead 13.8kV distribution system plant based on the evaluation of several criteria including age, condition, safety and reliability. Replacement of secondary conductor and right sizing of overhead distribution transformers was also undertaken in conjunction with this project.

Upgrades - Consumers Drive from Hopkins Street to Cannon Court - $227,000

This project included the upgrading of underground 13.8kV distribution system plant based on the evaluation of several criteria including age, condition, safety and reliability.

Replacement of underground distribution plant - Wentworth Street from Thickson Road to Boundary Road - $134,000

This project included the replacement of underground distribution plant with overhead 13.8kV distribution system plant based on the evaluation of several criteria including age, condition, cable failures, safety and reliability.

Tricont UG Rehabilitate - $112,000

This project is a continuation of the work started in 2005 that included the upgrading of underground 13.8kV distribution system plant based on the evaluation of several criteria including age, condition, cable failures, safety and reliability.

Miscellaneous System Improvements - $356,000

These are various system improvement projects undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system fault circuit indicators, replacement of pad mounted 15kV switchgear and various overhead and underground secondary service cables. System improvement projects were undertaken based on the evaluation of several criteria including age, asset condition, safety and reliability.

Distribution Station M.S. #10 - $168,000

This project included the installation of a circuit switcher for spare 12/16/20 MVA transformer to improve the operating efficiency of the distribution assets.

Various Reliability Projects - $262,000

There were nineteen separate projects undertaken throughout the service area in 2006. These projects were related to upgrades of distribution lines and station equipment based on the evaluation of several criteria including age, asset condition, safety and reliability. All of the individual projects were below the materiality threshold.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $544,000

In 2006, residential subdivision activity resulted in the connection of 1,058 residential lots. Costs were shared with the developers in accordance with the OEB's Distribution System Code economic evaluation model which resulted in the net addition of capital as noted.

SCADA:

Various SCADA Projects - $170,000

SCADA projects in 2006 were undertaken related to supervisory control and feeder monitoring at two (2) of Whitby Hydro's distribution transformer stations (M.S. #6 and M.S. #9) to enable station monitoring.

METERS:

Various Metering Work - $181,000

These costs relate to the installation of single phase and three phase meters in connection with new customers and various meter upgrades.

COMPUTER SOFTWARE:

Various Computer Software - $182,000

These costs relate to the upgrading of Whitby Hydro's financial system software.

FOR THE YEAR 2007

Whitby Hydro's net capital expenditures in 2007 were $6,801,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment.

Table 2-7: 2007 Capital Additions

2007 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	3,162,000		3,162,000
Reliability	2,668,000		2,668,000
Regulatory	250,000	99,000	151,000
Subdivision Development	1,750,000	1,406,000	344,000
Commercial Services	267,000	267,000	0
SCADA	95,000		95,000
Meters	154,000		154,000
Computer Hardware	101,000		101,000
Computer Software	88,000		88,000
Office Equipment & Tools	38,000		38,000
Total	**8,573,000**	**1,772,000**	**6,801,000**

CUSTOMER DEMAND:

Distribution Station M.S. # 15 - $322,000

This project included the installation of a new 3-6/8 MVA 44/13.8kV substation to supply new load growth in the area of Brock Street and Taunton Road. This cost represents the balance of the work completed in 2007 which was carried forward from 2006.

Non-poolable costs for New Whitby T.S. - $199,000

This project including the costs payable to Hydro One for the non-poolable costs related to the connection of the new transformer station (Whitby T.S.) located on Halls Road north of Taunton Road.

New Whitby T.S. Feeder Cable Egress - $858,000

This project includes 44 kV underground feeder cable and cable duct banks out of the Whitby TS along with required primary protective equipment to overhead pole lines located on Halls Road.

Hydro One Right-of-Way (Halls Rd. to Coronation Rd.) 4 - 44kV overhead feeders - $441,000

This project included the construction of 4 - 44kV subtransmission overhead feeders along Hydro One's transmission right-of-way between Hall's Road and Coronation Road to allow the utilization of capacity from the Whitby TS to service load growth in Whitby Hydro's service area.

Install New Pole line on Broadleaf Avenue, from M.S. #15 on McKinney Drive, to Baldwin St. - $136,000

This project included the construction of a new 44kV subtransmission pole line on McKinney Drive from Broadleaf Ave. to Baldwin St to service a new distribution station M.S. # 15.

Install new 44kV Feeder on McKinney Drive from M.S. # 15 to Taunton Road - $116,000

This project included the installation of a 44kV feeder from M.S. # 15 on McKinney drive south approximately one block to connect to an existing 44kV feeder on Taunton Road. This feeder allowed the connection of a 3-6/8 MVA 44/13.8kV distribution station M.S. # 15 to supply new load growth in the area.

2 New 44kV feeders south on Coronation Road from Whitby T.S. to Taunton Road - $412,000

This project included the construction of 2 - 44kV subtransmission overhead feeders along Coronation Road from Whitby TS to Taunton Road to utilize capacity of the new Whitby TS to provide capacity to supply new load growth in the area as well as improve the subtransmission system reliability.

13.8 kV Distribution System relocation in conjunction with the above 44kV pole work on Coronation Road - $106,000

This project relates to the repositioning of an existing 13.8kV overhead distribution feeder on Coronation Road in conjunction with the construction of the new 44kV pole line noted above.

2 New 44kV feeder east on Taunton Road (south side) from McKinney Dr. to Brock Street North - $160,000

This project included the construction of 2 - 44kV subtransmission overhead feeders along Taunton Road to utilize the new Whitby TS to provide capacity to supply new load growth in the area as well as improve the subtransmission system reliability. This project was undertaken in conjunction with a Region of Durham road relocation project.

Installation of 2 – 13.8kV Distribution Feeders on Broadleaf Ave. from M.S. # 15 to Brock Street - $116,000

This project included the construction of 2- 13.8 kV feeders on an existing pole line from M.S. # 15 on Broadleaf Avenue to Brock Street connecting into existing feeders to utilize capacity from M.S. #15 to supply new load growth in the area.

Various Customer Demand Projects - $296,000

There were eight separate projects undertaken in various locations throughout the service area in 2007. These projects were related to conductor upgrades, new services and line extensions to service new load growth. All of the individual projects were under the materiality threshold.

RELIABILITY PROJECTS:

Distribution Station M.S. # 10 - $159,000

This project included the installation of load tap changer pump and instrument transformers and associated hardware based on the evaluation of several criteria including age, condition, safety and reliability.

Underground Rehab - Bonacord Avenue from Frost Drive to Cochrane Street - $223,000

This project included the upgrading of underground 13.8kV distribution system plant based on the evaluation of several criteria including age, condition, safety and reliability.

Extend 1 - 44kV feeder from Brock St. on Taunton Road to Thickson Road and north on Thickson Road to Conlin Road - $1,025,000

This project included the construction of 1- 44kV subtransmission overhead feeder on Taunton Rd from Brock Street to Thickson Road and north on Thickson Road to Conlin Rd to create a feeder tie to utilize capacity of the new Whitby TS allowing improved system operability and increased reliability.

Miscellaneous System Improvements - $534,000

These are various system improvement projects undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system faulted circuit indicators, replacement of pad mounted 15kV switchgear, transformer upgrades and replacements and various overhead and underground secondary service cable upgrades.

Various Reliability Projects - $727,000

There were eighteen separate projects which were undertaken throughout the service area in 2007. These projects were related to upgrades of station equipment and overhead and underground lines based on the evaluation of several criteria including age, asset condition, safety and reliability. All of the individual projects were under the materiality threshold.

REGULATORY PROJECTS:

Various Regulatory Projects - $151,000

There were nine separate projects related to road relocation works undertaken by the road authorities within Whitby Hydro's service area. A portion of the costs were recovered from the road authorities resulting in a net capital addition of $151,000. All of the individual projects were under the materiality threshold.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $ 344,000

There were a number of residential subdivisions developed in 2007 which represented 658 residential lots. Costs were shared with the developers in accordance with the OEB's Distribution System Code economic evaluation model which yielded a net capital addition of $344,000.

METERS

Various Metering Work - $154,000

These costs are for the installation of single phase and three phase meters in connection with new customers and various wholesale meter upgrades.

FOR THE YEAR 2008

Whitby Hydro's net capital expenditures in 2008 were $7,504,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment.

Table 2-8: 2008 Capital Additions

2008 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	3,919,000		3,919,000
Reliability	1,576,000		1,576,000
Regulatory	1,051,000	293,000	758,000
Subdivision Development	2,944,000	2,443,000	501,000
Commercial Services	503,000	503,000	0
SCADA	39,000		39,000
Meters	298,000		298,000
Computer Hardware	154,000		154,000
Computer Software	228,000		228,000
Office Equipment & Tools	31,000		31,000
Total	**10,743,000**	**3,239,000**	**7,504,000**

CUSTOMER DEMAND:

Distribution Station M.S. #7- 2,485,000

This project included the upgrade of 4-6/8 MVA 44/13.8Kv Substation transformers to supply new load growth in the area of Thickson Road and Consumers Drive. The work entailed the station site preparation and civil works to install concrete equipment pads and associated cable duct banks, material cost of power transformers and protection equipment.

1 New 44kV feeder east on Taunton Road (south side) new pole line from Coronation Road to Brock Street North - $545,000

This project included the installation of a new pole line consisting of a new 44kV subtransmission feeder and new 13.8kV distribution feeder on Taunton Rd from Coronation to Brock St. This work included the installation of conductor and hardware on new poles to provide additional capacity in the area to service load growth as well as provide additional reliability and operation flexibility.

Extend 1 - 44kV Feeder on Coronation Road from Taunton to Rossland Road - $344,000

This project included the installation of a new 44kV subtransmission feeder on Coronation Road from Taunton to Rossland Road to provide additional capacity in the area a well as provide additional reliability and operation flexibility.

44kV and 13.8kV Feeder Extension on Taunton Road from Thickson Road to Future Commercial Development (north on Garrard Rd. from Taunton Rd.) - $277,000

This project included the repositioning of 2 -13.8kV distribution circuits in conjunction with the extension of a 44kV circuit to service customer load on Garrard Road north of Taunton Road.

Various Customer Demand Projects - $268,000

There were eight separate projects undertaken in various locations throughout the service area in 2008. These projects were related to conductor upgrades, new services and line extensions to service new load growth. All of the individual projects were under the materiality threshold.

RELIABILITY PROJECTS:

Miscellaneous System Improvements - $903,000

These were various system improvement projects undertaken throughout the service area consisting of the replacement of defective poles; installation of overhead and underground system faulted circuit indicators; replacement of pad mounted 15kV switchgear; transformer upgrades and replacements and various overhead and underground secondary service cable upgrades.

Various Reliability Projects - $673,000

There were fifteen separate projects undertaken throughout the service area in 2008. These projects were related to upgrades of station equipment and overhead and underground lines based on the evaluation of several criteria including age, asset condition, safety and reliability. All of the individual projects were under the materiality threshold.

REGULATORY PROJECTS:

Intersection Improvements at Highway #12 & Columbus Road - $305,000

This project required a portion a 13.8kV distribution system pole line to be relocated as a result of the MTO's plan to widen a portion of Highway # 12 at Columbus Road. A portion of the costs were recovered from the MTO resulting in a net capital addition of $305,000.

Pole Line Relocation on Garden Street from Dundas Street to Burns Street- $285,000

This project required a 44kV subtransmission pole line to be relocated as a result of the Municipality's decision to widen Garden Street from Dundas Street to Burn's Street. A portion of the costs were recovered from the Municipality resulting in a net capital addition of $285,000.

Various Regulatory Projects - $168,000

There were seven separate projects related to road relocation works undertaken by the road authorities within Whitby Hydro's service area. A portion of the costs were recovered from the road authorities resulting in a net capital addition of $168,000.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $501,000

There were a number of residential subdivisions developed in 2008 representing 876 residential lots. Costs were shared with the developer in accordance with the OEB's Distribution System Code economic evaluation model which yielded a net capital addition of $501,000.

METERS

Various Metering Work - $298,000

These costs relate to the installation of single phase and three phase meters in connection with new customers and various meter upgrades.

COMPUTER HARDWARE:

Various Computer Hardware - $154,000

These costs relate to a number of purchases of computer hardware components however, all of the in which individual costs were below the threshold. The hardware was related to financial, customer service and GIS hardware components.

COMPUTER SOFTWARE:

GIS Software Upgrade Phase One - $228,000

These costs were related to Whitby Hydro's major computer systems. They include phase one of two of the upgrading of GIS system software to allow for enhancement of data collection and record retention to enable Whitby Hydro to build on its asset management data base. Phase two of the upgrade would be undertaken in 2009. Other costs relate to minor upgrades to Whitby Hydro financial and customer information systems.

FOR THE YEAR 2009

Whitby Hydro's net capital expenditures in 2009 are forecast to be $5,383,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment.

Table 2-9: 2009 Capital Additions

2009 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	117,000	53,000	64,000
Reliability	4,324,000		4,324,000
Regulatory	464,000	98,000	366,000
Subdivision Development	895,000	732,000	163,000
Commercial Servicing	200,000	200,000	-
SCADA	41,000		41,000
Meters	120,000		120,000
Computer Hardware	95,000		95,000
Computer Software	185,000		185,000
Buildings	15,000		15,000
Office Equipment & Tools	10,000		10,000
Total	**6,466,000**	**1,083,000**	**5,383,000**

RELIABILITY PROJECTS:

Distribution Station M.S. #12 - $1,809,000

Project timing – April 2009 – Oct 2009

This project included the installation of a new 2-6/8 MVA 44/13.8kV distribution substation, associated site preparation and civil works to replace an aging 10/13 MVA 44/13.8kV power transformer in the area of Victoria Street and Brock Street South. This is phase one of the upgrading and eventual twinning of substation transformers that will be installed in 2012 under a Customer Demand project to supply new load in the area.

Given the age and condition of the existing equipment, the 10/13MVA power transformer and associated switchgear will be sold/scrapped when it is retired from service.

Distribution Station M.S. #12 Feeder Ingress - $106,000

Project timing – Aug 2009 – Oct 2009

This project includes the 44kV feeder ingress to distribution station #12 which entails the installation of riser poles, and 44kV underground conductor and associated switches and hardware required to energize the power transformers at the station.

Overhead Rehabilitation – Replacement of concrete pole on Brock Street South from Dunlop to Burns Street – $197,000

Project Timing – June 2009 – Sept 2009

This project includes the replacement of 11 concrete distribution system poles based on the evaluation of several criteria including age, condition, safety and reliability. Work included upgrading of secondary voltage conductor and the right sizing of distribution transformers.

Overhead Rehabilitation - Torian Ave and Montgomery Ave. - $126,000

Project Timing – June 2009 – Sept 2009

This project includes the replacement of wood distribution system poles based on the evaluation of several criteria including age, condition, safety and reliability. The project includes replacing existing high voltage and secondary conductor and right sizing distribution transformers.

Underground Rehab - Michael Blvd Subdivision (Phase 2 of 4) - $476,000

Project Timing – Sept 2009 – Dec 2009

This project includes the upgrading of underground 13.8kV distribution system plant based on the evaluation of an unacceptable frequency of cable failures in the area and the age of the plant.

The underground subdivision was originally installed in 1973. This is a multi phased project with 2009 work related to the replacement of poletran style transformers with pad mounted units. This will provide a higher level of flexibility in cable fault isolation and power restoration and reduce the duration of customer outages until such time as the underground high voltage cable is replaced in subsequent years. Upgrading secondary service connections are also to be undertaken to reduce the number of customer outages.

Miscellaneous System Improvements - $ 1,188,000

Project Timing – These projects are undertaken throughout the year

These are various system improvement projects undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system faulted circuit indicators, replacement of pad mounted 15kV switchgear, transformer upgrades and replacements, various overhead and underground secondary service cable upgrades based on the evaluation of several criteria including age, condition, safety and reliability.

Various Reliability Projects = $422,000

Project Timing – These projects are undertaken throughout the year

There are eleven separate projects whose individual costs are estimated to be under the materiality threshold that are to be undertaken throughout the service area in 2009. These projects are related to upgrades of distribution lines and station equipment based on the evaluation of several criteria including age, asset condition, safety and reliability.

REGULATORY PROJECTS:

Thickson Road widening from Rossland Road to Taunton Rd – $128,000

Project Timing – Nov 2009 – Dec 2009

This project includes a portion of 44kV subtransmission and 13.8kV distribution system pole line (6 poles) that must be relocated as a result of the Regional Municipality of Durham widening a portion of Thickson Rd**.** A portion of the costs will be recoverable from the Region of Durham.

Various Regulatory Projects - $238,000

Project Timing – These projects will be undertaken throughout the year and in service before December 31, 2009

There are eight projects related to road relocation works forecasted to be undertaken by the road authorities within Whitby Hydro's service area whose individual project costs are estimated to be below the materiality threshold. A portion of the costs are to be recovered from the road authorities.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $163,000

Project Timing – These projects are undertaken throughout the year

In 2009 residential subdivision development it is forecasted that 275 new residential lots will be connected. Costs will be shared with the developers in accordance with the OEB's Distribution System Code economic evaluation model which is expected to yield a net capital addition of $163,000.

METERS

Project Timing – These projects are undertaken throughout the year

Various Metering Work - $120,000

These capital costs relate to the installation of single phase and three phase meters in connection with new customers and various meter upgrades forecasted to be undertaken in 2009.

COMPUTER SOFTWARE:

Project Timing – March 2009 – July 2009

GIS Software Upgrade Phase 2 -$141,000

This project relates to phase two of the computer software upgrade and data conversion of Whitby Hydro's GIS system software which commenced in 2008.

Miscellaneous Software Costs - $44,000

The balance of software additions relates to various network system upgrades.

FOR THE YEAR 2010

Whitby Hydro's net capital expenditures in 2010 are forecast to be $8,409,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment. The effects of the harmonization of the commodity taxes have been incorporated in these costs.

Table 2-10: 2010 Capital Additions

2010 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	1,124,000		1,124,000
Reliability	3,409,000		3,409,000
Regulatory	3,685,000	1,380,000	2,305,000
Subdivision Development	1,905,000	1,013,000	892,000
Commercial Servicing	200,000	200,000	0
SCADA	80,000		80,000
Meters	132,000		132,000
Computer Hardware	86,000		86,000
Computer Software	204,000		204,000
Buildings	157,000		157,000
Office Equipment & Tools	20,000		20,000
Total	**11,002,000**	**2,593,000**	**8,409,000**

CUSTOMER DEMAND

Extension of 1 - 44 kV Feeder, South on Lakeridge Road from Taunton Rd to Dundas Street (Phase 1) - $713,000

Project Timing - May 2010 – Sept - 2010

This project includes the extension of a new overhead 44kV subtransmission feeder on Lakeridge Road from Rossland Road to Dundas Street. The line extension will allow utilization of transformer station capacity from the new Whitby TS as well as increased operating flexibility between 44 kV feeders to increase overall system reliability. The project requires the replacement of existing poles on Lakeridge Road to facilitate the additional height requirement for the new feeder.

Distribution System works required as a result of the extension of 1 - 44 kV Feeder South on Lakeridge Road from Taunton Rd to Dundas Street (Phase 1) - $255,000

Project Timing - May 2010 – Sept - 2010

This project is relates to work required on the 13.8 kV distribution system as a result of extending the 44kV subtransmission system on Lakeridge Road. Replacement of poles requires the relocation of the existing 13.8kV under build circuit to the new poles.

Various Customer Demand Projects - $156,000

There are two separate projects that are forecast to be undertaken in various locations throughout the service area in 2010 which individual costs are estimated to be under the materiality threshold. These projects are related to new services and line extensions to service new load growth.

RELIABILITY PROJECTS:

Distribution Station M.S. # 13 - $1,022,000

Project Timing - April 2010 – Sept 2010.

This is project includes the installation of 2-6/8 MVA 44/13.8kV power transformers at Distribution Station M.S. #13 replacing an aging 4kV power transformer to allow the commencement of voltage conversion from 4kV to 13.8kV to improve overall system reliability and supply new load growth in the area. Work will include the installation of concrete equipment pads and associated site work and the installation of power transformers and associated ancillary equipment.

2 - 13.8kV Distribution Feeders from M.S. 13 - Centre Street - $ 153,000

Project Timing - April 2010 – June 2010.

This project relates to the upgrading of power transformers at Distribution Station M.S. # 13 to commence voltage conversion in the downtown area. This work is required to upgrade aged 4kV overhead distribution plant to 13.8kV to allow the connection of new load growth in the area as well as to reduce line losses and upgrade reliability in the area.

Overhead Rehabilitation Projects - $380,000

Project Timing – These projects will be undertaken throughout the year

These projects include the upgrading of overhead 13.8kV distribution system plant based on the evaluation of several criteria including age, condition, safety and reliability.

The work entails the replacement of distribution poles, right sizing transformation and upgrading of the aged open wire secondary voltage service buss. Work will be undertaken on Diamond St, Scott St and Parkview Ave.

Underground Rehab - Michael Blvd Subdivision (Phase 3 of 4) - $630,000

Project Timing – Sept 2010 – Dec 2010

This project includes the upgrading of underground 13.8kV distribution system plant due to an unacceptable frequency of cable failures in the area and the age of the plant.

The underground subdivision was originally installed in 1973. This is a multi phased project with 2010 work related to the replacement of poletran style transformers with pad mounted units. This will provide a higher level of flexibility in cable fault isolation and power restoration and provide for reduced duration of customer outages when high voltage cable is replaced in subsequent years. Upgrading of secondary service connections will also be undertaken providing for reduced customer outages.

Miscellaneous System Improvements - $ 734,000

Project Timing – These projects are undertaken throughout the year

These are various system improvement projects undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system faulted circuit indicators, replacement of pad mounted 15kV switchgear, transformer upgrades and replacements, various overhead and underground secondary service cable upgrades based on the evaluation of several criteria including age, condition, safety and reliability.

Various Reliability Projects - $ 490,000

Project Timing – These projects are undertaken throughout the year

There are six separate projects which individual costs are below the materiality threshold that are forecast to be undertaken throughout the service area in 2010. These projects are related to upgrades of subtransmission lines and station equipment based on the evaluation of several criteria including age, asset condition, safety and reliability.

REGULATORY PROJECTS:

Region of Durham - $449,000

Project Timing – These projects will be undertaken throughout the year in conjunction and co-ordination with the Region of Durham road construction timing. They are expected to be in service by December 31, 2010.

The following projects are planned by the Region of Durham in 2010 which will require Whitby Hydro to relocate existing subtransmission and distribution system infrastructure required to clear conflict with the road improvements. A portion of the costs are recoverable from the Region of Durham.

Thickson Road (CN Rail South to Wentworth Street) widening to 4 lanes Reg. Rd. No. 26
Victoria Street (Lakeridge Rd. to Seaboard Gate)
Thickson Road Intersections, (Consumers Drive and Victoria Street)

Ministry of Transportation

Hwy #7 Construction from Lake Ridge Rd to Baldwin Street - $1,698,000

Project Timing – Jan 2010 – July 2010

This is a project which will entail a major relocation of existing subtransmission and distribution system infrastructure required to clear a conflict with the construction and widening of HWY #7. A portion of the costs are recoverable from the MTO.

Various Regulatory Projects - $158,000

Project Timing – These projects will be undertaken throughout the year and in service before December 31, 2009.

There are a number of small projects related to road relocation works forecast to be undertaken by the road authorities within Whitby Hydro's service area which individual costs are estimated to be below the materiality threshold. A portion of the costs are to be recovered from the road authorities.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $214,000

Project Timing – These projects are undertaken throughout the year

In 2010 residential subdivision development it is forecast that 385 new residential lots will be connected. Costs will be shared with the developers in accordance with the OEB's Distribution System Code economic evaluation model and which is forecast to yield a net capital addition of $214,000.

Secondary Services in Residential Subdivision - $678,000

This relates to the capitalization of the underground secondary service conductor on private property in new subdivisions. Please refer to the discussion of Secondary Services.

METERS

Various Metering Work - $132,000

Project Timing – These projects are undertaken throughout the year

These costs relate to the planned installation of three phase meters in connection with new customers and various meter upgrades as well as an upgrade of wholesale meters as prescribed by the IESO.

COMPUTER SOFTWARE:

Various Computer Software - $204,000

Project Timing – These projects are undertaken throughout the year

There are two separate projects whose individual costs are under the materiality threshold that are forecasted for 2010. The 2010 software costs include the procurement and installation of an electronic document filling and storage system and costs related to Whitby Hydro's GIS system.

BUILDINGS:

Various Building - $ 157,000

Project Timing – These projects are undertaken throughout the year

There are four separate projects whose individual costs are under the materiality threshold that are forecasted for 2010. These projects include security system upgrades and building energy efficiency upgrades.

FOR THE YEAR 2011

Whitby Hydro's net capital expenditures in 2011 are forecasted to be $6,190,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment. The effects of the harmonization of the commodity taxes have been incorporated in these costs.

Table 2-11: 2011 Capital Additions

2011 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	1,031,000		1,031,000
Reliability	2,877,000		2,877,000
Regulatory	4,187,000	2,730,000	1,457,000
Subdivision Development	1,279,000	1,024,000	255,000
Commercial Servicing	200,000	200,000	0
SCADA	82,000		82,000
Meters	95,000		95,000
Computer Hardware	65,000		65,000
Computer Software	106,000		106,000
Buildings	52,000		52,000
Office Equipment & Tools	20,000		20,000
Land	150,000		150,000
Total	**10,144,000**	**3,954,000**	**6,190,000**

CUSTOMER DEMAND PROJECTS

Extension of 1 -44kV Feeder South on Lakeridge Road from Dundas Street to Victoria Street (Phase 2) - $709,000

Project Timing – This project will be undertaken throughout 2011 in conjunction and co-ordination with the MTO road construction timing.

This project includes the extension of a new overhead 44kV subtransmission feeder on Lakeridge Road from Dundas Street to Victoria St. The line extension will allow utilization of transformer station capacity from the new Whitby TS as well as provide increased operating flexibility between 44 kV feeders. The project requires the replacement of existing poles on Lakeridge Road to facilitate the additional height requirement for the new feeder.

Distribution portion for 1-44kV feeder extension, South on Lakeridge Road from Dundas St. to Victoria St. (Phase 2) - $258,000

Project Timing – This project will be undertaken throughout 2011 in conjunction and co-ordination with the MTO road construction timing.

This project relates to works required on the 13.8 kV distribution system as a result of extending the 44kV subtransmission system on Lakeridge Road. Replacement of poles requires the relocation of the existing 13.8kV under build circuit to the new poles.

Various Customer Demand Projects - $64,000

Project Timing – These projects will be undertaken throughout the year

There are a few separate projects whose individual costs are under the materiality threshold that are forecasted to be undertaken in 2011. These projects are related to new customer connections.

RELIABILITY PROJECTS:

Upgrade of Batteries and 13.8kV Vacuum Breakers at Distribution Station M.S. 10 - $142,000

Project Timing – April 2011.

This project includes the replacement of station back up batteries and the retrofitting of four aged 13.8kV vacuum breakers based on the evaluation of several criteria including age, condition, safety and reliability.

Overhead Rehabilitation Projects - $580,000

Project Timing – These projects will be undertaken throughout the year

These projects include the upgrading of overhead 13.8kV distribution system overhead plant based on the evaluation of several criteria including age, condition, safety and reliability. The work entails the replacement of distribution poles and high voltage conductor on Meadow Rd and Meadow Crescent in the village of Brooklin and 25 poles in the Almond subdivision in the old down town area of Whitby. Work will also include the right sizing transformation and upgrading of aged open wire secondary voltage service buss as required.

Overhead Rehabilitation – Replacement of concrete pole on Brock Street South from Burns Street to Consumers Drive– $451,000

Project Timing – June 2011 – October 2011

This project includes the replacement of 25 concrete distribution system poles on Brock Street South based on the evaluation of several criteria including age, condition, safety and reliability. Work includes upgrading of secondary voltage conductor and the right sizing of distribution transformers.

Underground Rehab - Michael Blvd Subdivision (Phase 4 of 4) - $644,000

Project Timing – Sept 2011 – Dec 2011

This Reliability project will include the upgrading of underground 13.8kV distribution system plant due to an unacceptable level of cable failures in the area and the age of the plant.

The underground subdivision was originally installed in 1973. This is a multi phased project with 2011 work related to the replacement of poletran style transformers with pad mounted units. This will provide a higher level of flexibility in cable fault isolation and power restoration and reduce the duration of customer outages when high voltage cable is replaced in subsequent years. Upgrading of secondary service connections will also be undertaken to reduce customer outages.

Miscellaneous System Improvements - $ 773,000

Project Timing – These projects will be undertaken throughout the year and are expected to be completed by year end.

These are various system improvement projects forecast to be undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system faulted circuit indicators, replacement of pad mounted 15kV switchgear, transformer upgrades and replacements, various overhead and underground secondary service cable upgrades based on the evaluation of several criteria including age, condition, safety and reliability.

Various Reliability Projects - $287,000

Project Timing – These projects will be undertaken throughout the year and are expected to be completed by year end.

There are four separate projects whose individual costs are under the materiality threshold that are forecasted throughout the service area in 2011. These projects are related to upgrades of station equipment and distribution facilities based on the evaluation of several criteria including age, asset condition, safety and reliability.

REGULATORY PROJECTS:

Region of Durham - $232,000

Project Timing – This project will be undertaken in conjunction and co-ordination with the Region of Durham road construction timing.

The following project is forecast to be undertaken by the Region of Durham in 2011 which will require Whitby Hydro to relocate existing overhead subtransmission and distribution system infrastructure in order to clear a conflict with the Region's road improvements. A portion of the costs are recoverable from the Region of Durham.

Victoria Street East (East of Thickson Road to Oshawa Boundary) widening to 5 lanes

Ministry of Transportation – Hwy #407 Construction - $1,126,000 (Phase 1 of 3)

Project Timing – This project will be undertaken in consultation and co-ordination with the MTO road construction timing.

This project will entail the relocation of existing subtransmission and distribution system infrastructure in order to clear a conflict with the construction (extension) of the HWY 407. A portion of the costs are recoverable from the MTO.

Various Regulatory Projects - $99,000

Project Timing – These projects are undertaken throughout the year

There are four projects whose individual costs are under the materiality threshold that are forecasted to be undertaken by the Town of Whitby that relate to road relocation works.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $ 255,000

Project Timing – These projects are undertaken throughout the year

In 2011, residential subdivision development is forecasted to include connections of 425 new residential lots. Costs will be shared with the developers in accordance with the OEB's Distribution System Code economic evaluation model which is forecasted to yield a net capital addition of $255,000.

COMPUTER SOFTWARE:

Various Computer Software - $106,000

Project Timing – These projects are undertaken throughout the year

There are a small number of software upgrades and enhancements that are forecasted to be undertaken in 2011. These are related to Whitby Hydro's GIS system, customer information system and financial system.

LAND - $150,000

Project Timing – Project is to be undertaken in 2011 in conjunction with the Ministry of Transportation.

It is forecasted that a purchase of a one half acre parcel of land will be required for use as a distribution station site in preparation to supply new load growth in the area of the Hwy 407 expansion. Discussions have been initiated with the Ministry of Transportation to work on a collaborative basis to secure land while the MTO is negotiating property acquisitions for the 407 extension.

FOR THE YEAR 2012

Whitby Hydro's gross capital expenditures in 2012 are forecast to be $6,976,000 and are defined by the categories noted below. Projects above the materiality threshold are highlighted to describe the nature of the investment. The effects of the harmonization of the commodity taxes have been incorporated in these costs.

Table 2-12: 2012 Capital Additions

2012 CAPITAL ADDITIONS

Investment Category	Gross Additions	Contributions	Net Additions
Customer Demand	956,000		956,000
Reliability	2,675,000		2,675,000
Regulatory	5,941,000	3,306,000	2,635,000
Subdivision Development	1,294,000	1,024,000	270,000
Commercial Servicing	200,000	200,000	0
SCADA	84,000		84,000
Meters	122,000		122,000
Computer Hardware	65,000		65,000
Computer Software	107,000		107,000
Buildings	52,000		52,000
Office Equipment & Tools	10,000		10,000
Total	**11,506,000**	**4,530,000**	**6,976,000**

CUSTOMER DEMAND:

Distribution Station M.S. #12 - $632,000

Project timing – June 2012 – July 2012

This project will include the installation of 2-6/8 MVA 44/13.8kV additional substation transformers at M.S. # 12 located on Victoria Street West of Brock Street. The additional capacity of the substation is forecast to be required as a result of load growth in the area as a result of redevelopment of Whitby's lakeshore area as well as a result of the transfer of load from the 4kV to 13.8kV voltage conversion project.

Extension of 1-44kV and 1-13.8kV Feeder on Victoria St. (Lakeridge to Jeffrey) - $253,000

Project Timing – Aug 2012 – Oct 2012

This project includes the extension of a new 44kV subtransmission feeder and a new 13.8kV distribution feeder on Victoria Street from Lakeridge Road to Jeffery Street. The line extensions will provide needed capacity to service new load growth in the area as well as provided added reliability and operability of the subtransmission and distribution systems in the area.

Various Customer Demand Projects - $71,000
Project Timing – These projects are undertaken throughout the year

There are a few individual projects whose individual costs are under the materiality threshold that are forecasted to be undertaken in 2012. These projects are related to ne customer connections.

RELIABILITY PROJECTS:

4.16kV Conversion Project - $379,000 (Phase 1 of 3)
Project Timing - April 2009 - Dec 2009

This is phase 1 of a 3 year Reliability project that includes the upgrading of overhead 4kV distribution to a 13.8kV distribution system based on the evaluation of several criteria including age, condition, safety and reliability. The work for 2012 will include pole replacements, upgrading of primary and secondary conductor and right sizing of distribution transformers on Maria St, Palace St, Byron St N. and Colborne St W.

Overhead Rehabilitation Projects - $379,000
Project Timing – These projects are undertaken throughout the year as required.

These Reliability projects will involve the upgrading of overhead 13.8kV distribution system on plant based on the evaluation of several criteria including age, condition, safety and reliability. Work entails the replacement of deficient distribution poles, right sizing transformation and upgrading of aged open wire secondary voltage service bus as required. Areas affected will be George St, Cassels Rd and Durham St in the village of Brooklin.

Underground Cable Replacement - West Lynde Subdivision (Phase 1of 4) - $632,000
Project Timing – July 2011 – Sept 2011

This is the first year of a four year Reliability project that will include the upgrading of underground 13.8kV distribution system plant based on the evaluation of several criteria including age, condition, safety and reliability. The existing plant is 35 years old and the area has experienced a high number of cable faults. Work will entail the replacement of 15kV high voltage cable underground cable between pad mounted transformers. Work will be undertaken in a systematic manner to limit the need for power outages to customers.

Miscellaneous System Improvements - $ 758,000

Project Timing – These projects will be undertaken and completed throughout the year as required.

These are various system improvement projects forecast to be undertaken throughout the service area consisting of the replacement of defective poles, installation of overhead and underground system faulted circuit indicators, replacement of pad mounted 15kV switchgear, transformer upgrades and replacements, various overhead and underground secondary service cable upgrades based on the evaluation of several criteria including age, condition, safety and reliability.

Various Reliability Projects - $527,000

Project Timing – These projects will be undertaken and completed throughout the year as required.

There are seven separate projects whose individual costs are under the materiality threshold that are forecasted throughout the service area in 2012. These projects are related to upgrades of station equipment and distribution facilities based on the evaluation of several criteria including age, asset condition, safety and reliability.

REGULATORY PROJECTS:

Region of Durham - $1,446,000

Project Timing – These projects will be undertaken and completed throughout the year in conjunction and co-ordination with the Region of Durham road construction timing.

The following Regulatory projects are forecast to be undertaken by the Region of Durham in 2012 which will require Whitby Hydro to relocate existing subtransmission and distribution system infrastructure in order to clear a conflict with the Region's road improvements. A portion of the costs are recoverable from the Region of Durham.

- Lakeridge Road (Victoria Street to Taunton Road approx. 6km) widening from 2 to 5 lanes
- Hopkins Street (Consumers Drive to Dundas St. approx. 1.7 km) widening from 2 to 5 lanes & New CPR grade separation
- Henry Street (Dundas Street, South to Hwy. 401) Reconstruct and urbanize road

Ministry of Transportation – Hwy #407 Construction - $1,092,000 (Phase 2 of 3)

Project Timing – This project will be undertaken and completed in conjunction and co-ordination with the MTO road construction timing.

This project will entail the relocation of existing subtransmission and distribution system infrastructure in order to clear a conflict with the construction of the HWY 407 extension. A portion of the costs are recoverable from the MTO.

Various Regulatory Projects - $97,000

Project Timing – These projects are to be undertaken throughout the year

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There are five projects whose individual costs are under the materiality threshold that are forecasted to be undertaken by the Town of Whitby that relate to road relocation works.

SUBDIVISION DEVELOPMENT:

Various Subdivision Developments - $ 270,000

Project Timing – These projects will be undertaken and completed throughout the year as required.

There are a number of residential subdivisions forecast to be developed in 2012 representing 450 residential lots. Costs will be shared with the developers in accordance with the OEB's Distribution system Code economic evaluation model.

METERS

Various Metering Work - $122,000

Project Timing – This work will be undertaken and completed throughout the year as required.

These costs relate to the installation of single phase and three phase meters in connection with new customers and various meter upgrades.

COMPUTER SOFTWARE - $107,000

Project Timing – This work will be undertaken and completed throughout the year.

This cost relates to continued upgrading of Whitby Hydro's GIS system, customer information system and financial system.

SECONDARY SERVICES IN RESIDENTIAL SUBDIVISION

Background

Construction Process of Subdivision plant

The installation of the underground electrical distribution plant in residential subdivisions is typically undertaken in stages. The main electrical plant which consists of high voltage cables, pad mounted transformers and secondary voltage cables are first installed on the street right of way.

Timing differences from when the main electrical plant is installed on the street and when the houses are actually built can be significant depending on developers scheduling and house sales. Given this time lag, the secondary cables are initiated in the pad mounted transformer but are terminated on the street right of way directly in front of the lot in accordance with the location of the future meter base. This secondary cable configuration is referred to as the service drop.

When the house is finally constructed and is ready for electrical servicing, the builder is responsible to arrange for the installation of the secondary service cable installation from the location of where main secondary service drop is located, to the meter base location on the outside of the house. In most cases the builder is uses a different contractor for this work then the developer uses for the installation of the main electrical plant.

Rate Base Treatment of Secondary Services

At the time of deregulation of the electrical industry in Ontario, utilities were allowed to include all contributed capital related to the electrical plant installed in residential subdivisions in their rate base until November 2000. However, in some cases, and as in Whitby Hydro's case, the capital value of the secondary service cable for from the service drop location on the street to the meter base was not included in the contributed capital that was allowed in rate base at that time. Whitby Hydro's demarcation point is the meter base and as a result Whitby Hydro is responsible for the replacement and maintenance of these secondary services.

Value of Secondary Services

Whitby Hydro engaged the services of Deloitte & Touche to conduct an appraisal of its assets for tax purposes. A value for the secondary services accumulated from inception to November 1st, 2000 was determined and became part of the appraised value of assets for tax purposes (see Table 2-13).

Adjustment to Rate Base

The 2006 Rate Rebasing process did not allow for any modifications to rate base other than strictly defined Tier 1 and Tier 2 adjustments for which the secondary services did not qualify.

The net book value of these assets as of December 31, 2009 is $678,000 and has been included as the additions to Account 1855 Services and the associated depreciation has been adjusted. (See Table 2-14).

Table 2-13: Net Book Value as of November 1, 2000 – Secondary Services

Year	Transformer Additions	Customers per Transformer	New Services-Customer Additions	Cost per Secondary Service	Dollar Value of New Services	Yearly Depreciation Expense	Number of Years Depreciated	Accumulated Depreciation	Net Book Value
2000			928	250	232,083	9,283	0.83	7,705	224,378
1999			1,136	250	284,000	11,360	2	22,720	261,280
1998			389	250	97,250	3,890	3	11,670	85,580
1997			516	240	123,840	4,954	4	19,816	104,024
1996			147	240	35,280	1,411	5	7,055	28,225
1995	35	10	350	240	84,000	3,360	6	20,160	63,840
1994	24	10	240	230	55,200	2,208	7	15,456	39,744
1993	80	10	800	230	184,000	7,360	8	58,880	125,120
1992	78	10	780	230	179,400	7,176	9	64,584	114,816
1991	64	10	640	220	140,800	5,632	10	56,320	84,480
1990	40	10	400	220	88,000	3,520	11	38,720	49,280
1989	52	10	520	210	109,200	4,368	12	52,416	56,784
1988	41	10	410	210	86,100	3,444	13	44,772	41,328
1987	63	10	630	200	126,000	5,040	14	70,560	55,440
1986	25	10	250	200	50,000	2,000	15	30,000	20,000
1985	36	10	360	200	72,000	2,880	16	46,080	25,920
1984	8	10	80	190	15,200	608	17	10,336	4,864
1983	27	10	270	190	51,300	2,052	18	36,936	14,364
1982	8	10	80	190	15,200	608	19	11,552	3,648
1981	8	10	80	190	15,200	608	20	12,160	3,040
1980	6	10	60	180	10,800	432	21	9,072	1,728
1979	4	10	40	180	7,200	288	22	6,336	864
1978	16	10	160	180	28,800	1,152	23	26,496	2,304
1977	56	10	560	170	95,200	3,808	24	91,392	3,808
1976	11	10	110	170	18,700	748	25	18,700	0
1975	8	10	80	170	13,600			13,600	-
1974	10	10	100	170	17,000			17,000	-
1973	5	10	50	170	8,500			8,500	-
1972	7	10	70	170	11,900			11,900	-
1971	7	10	70	170	11,900			11,900	-
1970	4	10	40	170	6,800			6,800	-
1969	4	10	40	170	6,800			6,800	-
1968	16	10	160	170	27,200			27,200	-
1967	4	10	40	170	6,800			6,800	-
	747				2,315,253	88,190		900,394	1,414,859

Notes:
1. Customer additions are residential customers
2. Prior to customer addition data was not available so transformer additions were used. Assumption that with every transformer added there are 10 customers added.

1 **Table 2-14: Net Book Value as of December 31, 2009 – Secondary Services**

Year	Transformer Additions	Customers per Transformer	New Services-Customer Additions	Cost per Secondary Service	Dollar Value of New Services	Yearly Depreciation Expense	Number of Years Depreciated	Accumulated Depreciation	Net Book Value
2000			928	250	232,083	9,283	10	92,830	139,253
1999			1,136	250	284,000	11,360	11	124,960	159,040
1998			389	250	97,250	3,890	12	46,680	50,570
1997			516	240	123,840	4,954	13	64,402	59,438
1996			147	240	35,280	1,411	14	19,754	15,526
1995	35	10	350	240	84,000	3,360	15	50,400	33,600
1994	24	10	240	230	55,200	2,208	16	35,328	19,872
1993	80	10	800	230	184,000	7,360	17	125,120	58,880
1992	78	10	780	230	179,400	7,176	18	129,168	50,232
1991	64	10	640	220	140,800	5,632	19	107,008	33,792
1990	40	10	400	220	88,000	3,520	20	70,400	17,600
1989	52	10	520	210	109,200	4,368	21	91,728	17,472
1988	41	10	410	210	86,100	3,444	22	75,768	10,332
1987	63	10	630	200	126,000	5,040	23	115,920	10,080
1986	25	10	250	200	50,000	2,000	24	48,000	2,000
1985	36	10	360	200	72,000	2,880	25	72,000	-
1984	8	10	80	190	15,200			15,200	-
1983	27	10	270	190	51,300			51,300	-
1982	8	10	80	190	15,200			15,200	-
1981	8	10	80	190	15,200			15,200	-
1980	6	10	60	180	10,800			10,800	-
1979	4	10	40	180	7,200			7,200	-
1978	16	10	160	180	28,800			28,800	-
1977	56	10	560	170	95,200			95,200	-
1976	11	10	110	170	18,700			18,700	-
1975	8	10	80	170	13,600			13,600	-
1974	10	10	100	170	17,000			17,000	-
1973	5	10	50	170	8,500			8,500	-
1972	7	10	70	170	11,900			11,900	-
1971	7	10	70	170	11,900			11,900	-
1970	4	10	40	170	6,800			6,800	-
1969	4	10	40	170	6,800			6,800	-
1968	16	10	160	170	27,200			27,200	-
1967	4	10	40	170	6,800			6,800	-
	747				2,315,253	77,886		1,637,566	677,687

Adjustments to Rate Base		
2010	Additions	677,687
2010	Depreciation	77,886
	Less 1988 depreciation	-2,880
		75,006

RATE BASE OVERVIEW

As outlined in the 2006 EDR Handbook, an average of the net fixed asset balances (opening and closing) for the 2010 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and distribution expenses is used in calculating the rate base.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Table 2-15 outlines Whitby Hydro's rate base calculations for the years including 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year.

Table 2-15: Summary of Rate Base

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge Year	2010 Test Year
Gross Fixed Assets	96,147	106,920	113,693	121,155	126,482	134,868
Accumulated Depreciation	-43,581	-51,084	-55,189	-59,555	-64,093	-69,022
Net Book Value	52,566	55,836	58,504	61,600	62,389	65,846
Average Net Book Value	50,828	54,553	57,170	60,052	61,995	64,118
Working Capital	65,179	67,208	70,969	71,300	77,274	77,883
Working Capital Allowance	9,777	10,081	10,645	10,695	11,591	11,682
Rate Base	60,605	64,634	67,815	70,747	73,586	75,800
Working Capital Detail						
Cost of Power	57,978	59,047	62,242	63,151	68,788	68,963
Operation	1,513	1,786	1,984	1,832	1,866	1,971
Maintenance	1,136	1,678	1,907	1,636	1,870	1,890
Billing and Collections	1,753	2,264	2,300	2,168	2,041	2,166
Administrative and General	2,799	2,433	2,536	2,513	2,709	2,893
Working Capital	65,179	67,208	70,969	71,300	77,274	77,883

RATE BASE VARIANCE ANALYSIS

Overview

Table 2-16 provides Whitby Hydro's rate base year over year variances for rate base by major component. The 2010 Test Year rate base is $75.8M which is 25.07% higher than the 2006 Board Approved rate base of $60.6M which represents an annual average increase of 3.89% compounded per year.

Whitby Hydro has experienced extreme demand growth increasing its customer base by 49.7% over the past 9 years (1999-2008). The growth rate over the rebasing period (2004-2010) continues at a more moderate rate of 13.4%; it appears to be easing off in 2007 and 2008 and is forecast to be less than 1.0% in 2009 and 2010 due to economic conditions. The customer growth rate from 1999-2010 is currently projected to increase by 52.1%. Capital expenditure detail by project is provided in Table 2-4 through 2-12 and Working Capital Components are outlined in Table 2-18 - Rate Base Variances.

Table 2-16: Rate Base Variances

Description	2006 Board Approved	2006 Actual	Variance - Board Approved to Actual	2007 Actual	Variance - 2007 Actual to 2006 Actual	2008 Actual	Variance - 2008 Actual to 2007 Actual	2009 Bridge	Variance - 2009 Actual to 2008 Actual	2010 Test	Variance - 2010 Actual to 2009 Actual
Gross Fixed Assets	96,147	106,920	10,773	113,693	6,773	121,155	7,462	126,482	5,327	134,868	8,386
Accumulated Depreciation	-43,581	-51,084	-7,503	-55,189	-4,105	-59,555	-4,366	-64,093	-4,538	-69,022	-4,929
Net Book Value	52,566	55,836	3,270	58,504	2,668	61,600	3,096	62,389	789	65,846	3,457
Average Net Book Value	50,828	54,553	3,725	57,170	2,617	60,052	2,882	61,995	1,943	64,118	2,123
Working Capital	65,179	67,208	2,029	70,969	3,761	71,300	331	77,274	5,974	77,883	609
Working Capital Allowance	9,777	10,081	304	10,645	564	10,695	50	11,591	896	11,682	91
Rate Base	60,605	64,634	4,029	67,815	3,181	70,747	2,932	73,586	2,839	75,800	2,214
Variance from Previous Year		4,029		3,181		2,932		2,839		2,214	
% Change -Year over Year		6.65%		4.92%		4.32%		4.01%		3.01%	
% Change Test Year to Most Current Actual (2010 vs. 2008)										7.14%	
% Change 2010 Test Year to 2006 Board Approved										25.07%	
Average for 2006, 2007 & 2008				5.30%							
Compound Annual Growth Rate for 2006, 2007, 2008				4.42%							
Compound Annual Growth Rate for 2006 Board Approved to 2010 Test Year										3.80%	

A Cost Trending Analysis (see table below) has been developed to use as a proxy to support rate base trends and percentage increases. When the customer growth rates are combined with the industry inflation rate, rate base trends for the period of 2004-2010 should have increased by 24.9 per cent which is in line with the with the forecast cost increases of 25.07%

Cost Trending Analysis

	2004 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Customer Growth	35,146	37,649	38,279	39,226	39,467	39,856
% Change		7.12	1.67	2.47	0.61	0.99
% Change-ytd		7.12	8.91	11.61	12.29	13.40
IPI*	103.3	107.9	110.3	112.9	114.0	115.2
% Change		4.45	2.22	2.36	1.00	1.00
% Change-ytd		4.45	6.78	9.29	10.39	11.49
Total sum of Customer Growth and IPI Change -%						24.89

*IPI (Implicit chain price indexes-Statistics Canada)
** 2009 and 2010 are based on the November 2009 change in C.P.I.

2006 Actual vs. 2006 Board Approved:

The rate base of $64.6M was greater than the 2006 Board Approved by $4.0M due to expansion in net fixed assets of $3.7M and working capital of $.3M. Net fixed assets for 2006 Board approved is an average of 2003 and 2004 actual amounts. The 2006 actual net fixed assets are based on an average of 2005 and 2006 actuals which are higher due to the additional net investments (additions less depreciation) made in these years.

2007 Actual vs. 2006 Actual:

The rate base of $67.8M was greater than the 2006 Actual by $3.2M due to expansion in net fixed assets of $2.6M and working capital of $0.6M.

2008 Actual vs. 2007 Actual:

The rate base of $70.7M was greater than the 2007 Actual by $2.9M due to expansion in net fixed assets.

2009 Bridge Year vs. 2008 Actual:

The rate base of $73.6M was greater than the 2008 Actual by $2.8M due to expansion in net fixed assets of $1.9M and working capital of $0.9M.

2010 Test Year vs. 2009 Bridge Year:

The rate base of $75.8M was greater than the 2009 Actual by $2.2M due to expansion in net fixed assets.

WORKING CAPITAL CALCUATIONS

OVERVIEW

Whitby Hydro's working capital allowance is forecast to be $11,682K for 2010 and is based on the 15% of specific OM&A accounts formula approach referred to on page 15 of the Board's Filing Requirements. Whitby Hydro 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 2-17. The 2010 Test Year working capital has increased by $1,906K or 19.5% from the 2006 Board Approved amount which is predominantly due to increases in the cost of power at $1,647 or 16.8%.

Table 2-17: Analysis of Change in Working Capital for 2006 Board Approved to 2010 Test Year

Working Capital Detail	2006 Board Approved Expenses	2006 Board Approved Working Capital	2010 Test Year Expenses	2010 Test Year Working Capital	$ Change in Working Capital - 2010 Test to 2006 Board	% Change in Working Capital - 2010 Test to 2006 Board
Cost of Power	57,978	8,697	68,963	10,344	1,647	16.8%
Operation	1,513	227	1,971	296	69	0.7%
Maintenance	1,136	170	1,890	284	114	1.2%
Billing and Collections	1,753	263	2,166	325	62	0.6%
Administrative and General	2,799	420	2,893	434	14	0.1%
Total	65,179	9,777	77,883	11,683	1,906	19.5%

COST OF POWER FORECAST

Whitby's cost of power forecast for 2010 included in working capital allowance calculations includes charges for electricity commodity, network and connection transmission charges, low voltage charges and rural rate protection charges.

The forecasts were developed using appropriate unit pricing applied to Whitby's 2010 load and energy forecasts, assuming that the total retail volumes billed, inclusive of losses represent the total wholesale volumes billed.

Details of the cost of power calculations, including individual rates and purchase levels can be found in Whitby Hydro's rate model (Sheet C2).

Table 2-18: Calculation of Working Capital Allowance

Expense Description	2006 EDR Approved	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
Cost of Power											
4705 Power Purchased	43,514,210	45,176,565	6,776,485	48,346,420	7,251,963	49,846,305	7,476,946	54,241,887	8,136,283	54,537,119	8,180,568
4708 Charges - WMS	5,139,777	4,503,856	675,578	4,554,353	683,153	5,116,088	767,413	4,605,026	690,754	4,630,090	694,514
4710 Cost of Power Adjustments	1,246,587	-	-	-	-	-	-	-	-	-	-
4714 Charges - NW	4,328,099	4,833,005	724,951	4,777,703	716,655	3,934,043	590,106	4,191,212	628,682	4,442,402	666,360
4716 Charges - CN	3,749,547	4,215,105	632,266	4,150,055	622,508	3,767,819	565,173	4,168,576	625,286	3,992,393	598,859
4750 Charges - LV	-	318,442	47,766	413,236	61,985	486,881	73,032	480,388	72,058	203,590	30,539
4730 Rural Rate Adjustments								1,101,259	165,189	1,157,523	173,628
Subtotal - Cost of Power Expense	**57,978,220**	**59,046,972**	**8,857,046**	**62,241,766**	**9,336,264**	**63,151,136**	**9,472,670**	**68,788,347**	**10,318,252**	**68,963,116**	**10,344,468**
Operations											
5005 Operation Supervision and Engineering	91,670	125,200	18,780	126,778	19,017	87,155	13,073	85,129	12,769	93,099	13,965
5010 Load Dispatching	333,129	323,535	48,530	387,010	58,052	282,424	42,364	322,791	48,419	350,806	52,621
5012 Station Buildings and Fixtures Expense	99,370	113,139	16,971	130,233	19,535	120,097	18,015	124,860	18,729	129,033	19,355
5014 Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-	-	-
5015 Transformer Station Equipment - Operation Supplies a	-	-	-	-	-	-	-	-	-	-	-
5016 Distribution Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-	-	-
5017 Distribution Station Equipment - Operation Supplies a	12,299	13,248	1,987	19,097	2,865	34,376	5,156	22,249	3,337	41,533	6,230
5020 Overhead Distribution Lines & Feeders - Operation La	-	-	-	-	-	-	-	-	-	-	-
5025 Overhead Distribution Lines & Feeders - Operationn S	10,156	31,406	4,711	22,217	3,333	31,648	4,747	31,742	4,761	48,705	7,306
5030 Overhead Subtransmission Feeders - Operation	5,612	5,264	790	4,807	721	21,456	3,218	21,389	3,208	29,881	4,482
5035 Overhead Distribution Transformers - Operation	8,050	11,296	1,694	10,199	1,530	8,436	1,265	14,345	2,152	23,939	3,591
5040 Underground Distribution Lines & Feeders - Operatior	-	-	-	-	-	-	-	-	-	-	-
5045 Underground Distribution Lines & Feeders - Operatior	135,651	154,872	23,231	184,088	27,613	188,976	28,346	220,948	33,142	240,400	36,060
5050 Undergound Subtransmission Feeders - Operation	242	-	-	-	-	-	-	-	-	-	-
5055 Undergound Distribution Transformers - Operation	7,314	16,483	2,472	11,830	1,775	9,896	1,484	12,746	1,912	29,701	4,455
	-	-	-	-	-	-	-	-	-	-	-
5065 Meter Expense	432,384	496,427	74,464	550,001	82,500	537,465	80,620	400,122	60,018	369,727	55,459
5070 Customer Premises - Operation Labour	-	-	-	-	-	-	-	-	-	-	-
5075 Customer Premises - Materials & Expenses	65,912	53,139	7,971	61,483	9,222	77,725	11,659	140,288	21,043	142,492	21,374
5085 Miscellaneous Distribution Expense	302,042	431,557	64,734	475,543	71,331	417,675	62,651	468,001	70,200	470,285	70,543
5090 Underground Distribution Lines & Feeders - Rental Pa	1,854	-	-	-	-	-	-	-	-	-	-
5095 Overhead Distribution Lines & Feeders - Rental Paid	7,390	10,459	1,569	543	81	14,902	2,235	1,120	168	1,120	168
5096 Other Rent		-	-	-	-	-	-	-	-	-	-
Subtotal Operations	**1,513,075**	**1,786,025**	**267,904**	**1,983,829**	**297,575**	**1,832,230**	**274,833**	**1,865,730**	**279,858**	**1,970,721**	**295,609**

Expense Description	2006 EDR Approved	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
Maintenance											
5105 Maintenance Supervision and Engineering	88,221	171,479	25,722	179,112	26,867	134,535	20,180	133,176	19,976	155,860	23,379
5110 Maintenance of Buildings and Fixtures - Distribution St	5,230	2,539	381	2,720	408	8,092	1,214	5,820	873	5,815	872
5112 Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-	-	-
5114 Maintenance of Distribution Station Equipment	275,086	397,036	59,555	508,360	76,254	306,851	46,028	303,762	45,564	316,127	47,419
5120 Maintenance of Poles, Towers and Fixtures	18,486	61,438	9,216	75,648	11,347	62,055	9,308	65,259	9,789	75,903	11,385
5125 Maintenance of Overhead Conductors and Devices	183,385	283,229	42,484	242,426	36,364	303,023	45,453	349,363	52,404	310,822	46,623
5130 Maintenance of Overhead Services	63,247	65,931	9,890	62,261	9,339	73,724	11,059	111,369	16,705	122,149	18,322
5135 Overhead Distribution Lines & Feeders - Right of Way	50,120	101,083	15,162	87,615	13,142	109,546	16,432	127,005	19,051	131,392	19,709
5145 Maintenance of Underground Conduit	105	-	-	-	-	-	-	-	-	-	-
5150 Maintenance of Underground Conductors & Devices	167,521	201,308	30,196	295,227	44,284	175,145	26,272	260,128	39,019	213,900	32,085
5155 Maintenance of Underground Services	141,448	177,875	26,681	233,802	35,070	276,260	41,439	262,258	39,339	280,646	42,097
5160 Maintenance of Line Transformers	135,289	195,960	29,394	197,518	29,628	156,046	23,407	197,085	29,563	219,350	32,903
5172 Sentinel Lights - Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-
5175 Maintenance of Meters	7,910	20,455	3,068	22,529	3,379	30,080	4,512	54,734	8,210	58,030	8,705
Subtotal Maintenance	**1,136,048**	**1,678,333**	**251,749**	**1,907,218**	**286,082**	**1,635,357**	**245,304**	**1,869,959**	**280,493**	**1,889,994**	**283,499**
Billing & Collections	-										
5305 Supervision	27,283	45,726	6,859	30,503	4,575	45,078	6,762	34,003	5,100	35,063	5,259
5310 Meter Reading Expense	184,831	243,682	36,552	196,987	29,548	264,107	39,616	253,541	38,031	258,184	38,728
5315 Customer Billing	793,344	535,334	80,300	559,722	83,958	593,483	89,022	603,108	90,466	680,570	102,086
5320 Collecting	113,798	133,337	20,001	131,478	19,722	143,910	21,587	140,488	21,073	143,336	21,500
5325 Collecting - Cash Over & Short	-	-	-	-	-	-	-	-	-	-	-
5330 Collection Charges	10,163	12,613	1,892	19,680	2,952	20,034	3,005	18,135	2,720	20,359	3,054
5335 Bad Debt Expense	57,589	135,171	20,276	113,528	17,029	304,939	45,741	200,000	30,000	200,000	30,000
5340 Miscellaneous Customer Accounts Expense	562,784	686,886	103,033	697,626	104,644	792,092	118,814	785,283	117,792	814,854	122,228
Subtotal Billing & Collections	**1,749,792**	**1,792,749**	**268,913**	**1,749,525**	**262,428**	**2,163,643**	**324,547**	**2,034,558**	**305,182**	**2,152,366**	**322,855**
Community Relations											
5415 Energy Conservation	-	466,290	69,944	547,418	82,113	-	-	-	-	-	-
5425 Miscellaneous Customer Service & Informational Expe	3,448	4,405	661	3,306	496	4,643	696	6,801	1,020	13,572	2,036
Subtotal Community Relations	**3,448**	**470,695**	**70,605**	**550,724**	**82,609**	**4,643**	**696**	**6,801**	**1,020**	**13,572**	**2,036**

Expense Description	2006 EDR Approved	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
Administrative & General Expense											
5605 Executive Salaries & Expenses	656,757	95,253	14,288	128,465	19,270	120,964	18,145	79,450	11,918	60,170	9,026
5610 Management Salaries & Expenses	149,546	722,628	108,394	667,115	100,067	793,372	119,006	859,268	128,890	913,739	137,061
5615 General Administrative Salaries & Expense	271,841	342,789	51,418	418,163	62,724	379,086	56,863	411,278	61,692	479,310	71,897
5620 Office Supplies and Expense	130,753	125,422	18,813	135,151	20,273	99,150	14,873	106,400	15,960	109,760	16,464
5630 Outside Services Employed	74,948	165,635	24,845	127,694	19,154	197,068	29,560	214,400	32,160	238,880	35,832
5635 Property Insurance	11,491	30,360	4,554	30,360	4,554	33,188	4,978	36,000	5,400	37,000	5,550
5640 Injuries and Damages	149,839	71,905	10,786	84,217	12,633	85,655	12,848	85,000	12,750	88,000	13,200
5645 Employee Pensions & Benefits	183,391	-	-	-	-	-	-	-	-	-	-
5655 Regulatory Expense	129,358	271,883	40,782	257,611	38,642	288,947	43,342	354,108	53,116	392,429	58,864
5660 General Advertising Expense	-	5,842	876	1,712	257	1,554	233	2,240	336	2,240	336
5665 Miscellaneous General Expense	727,282	398,913	59,837	420,474	63,071	330,757	49,614	296,600	44,490	300,240	45,036
5670 Rent	-	-	-	-	-	-	-	-	-	-	-
5675 Maintenance of General Plant	313,686	202,706	30,406	265,306	39,796	183,457	27,519	224,000	33,600	231,000	34,650
5685 Independent Market Operator Fees & Penalties	-	-	-	-	-	-	-	40,000	6,000	40,000	6,000
Subtotal Administrative & General Expense	**2,798,892**	**2,433,335**	**364,999**	**2,536,267**	**380,441**	**2,513,198**	**376,981**	**2,708,744**	**406,312**	**2,892,768**	**433,916**
TOTAL	**65,179,475**	**67,208,110**	**10,081,216**	**70,969,328**	**10,645,399**	**71,300,208**	**10,695,031**	**77,274,139**	**11,591,117**	**77,882,537**	**11,682,383**

CAPITALIZATION POLICY

Purpose:

To provide direction on the classification of expenditures as Capitalized Assets; these assets may be either tangible (Property, Plant and Equipment) or intangible (software and other rights or licenses).

Policy:

Expenditures are capitalized to ensure that there is an equitable allocation of costs among existing and future customers. Assets are expected to provide future economic benefits for more than one year. Expenditures incurred for the acquisition, construction, development or betterment of assets should be capitalized and allocated over the estimated useful lives of the related assets through amortization.

Property, Plant and Equipment

Property, Plant and Equipment are tangible assets that meet all of the following criteria:

- are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other property, plant and equipment;
- have been acquired, constructed or developed with the intention of being used on a continuing basis; and
- are not intended for sale in the ordinary course of business.

Intangible Assets

Intangible assets are identifiable non-monetary assets that lack physical substance but provide a financial or operating advantage.

Betterment

The cost incurred to enhance the service potential of an item of property, plant and equipment is a betterment. 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.

Materiality Limits

Expenditures for capital assets are subject to materiality limits as at times the administrative costs of capitalizing an asset may outweigh the benefits.

For identifiable assets items less than $500.00 are expensed. For expenditures that are for a component of a grouped asset the limit will apply to the total value of all the components.

A readily identifiable asset is an asset that has a material unit cost for financial reporting purposes and is tracked on an individual unit basis.

Grouped assets are those assets that by their nature make identification of individual components impractical.

Costs to be Capitalized

Property, plant and equipment should be recorded at cost, which includes the purchase price and other acquisition costs such as: option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges.

The cost of construction properly included in the electric plant accounts shall include where applicable, the cost of labour; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machinery services; and such portion of general engineering, administrative salaries and expenses, insurance, taxes, and other similar items as may be properly included in construction costs.

FIXED ASSET & ACCUMULATED DEPRECIATION CONTINUITY SCHEDULES

Schedule 4-1: For the Year Ending December 31, 2006

Fixed Asset Continuity Schedule
as at December 31, 2006

		Cost				Accumulated Depreciation				
OEB	**Description**	**2006 EDR Approved**	**Additions**	**Disposals**	**Closing Balance**	**2006 EDR Approved**	**Amortization Expense**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	228,318	17,467	0	245,786	0	0	0	0	228,318
1806	Land Rights	22,922	33,893	(18,338)	38,477	0	0	0	0	22,922
1808	Buildings and Fixtures	1,117,302	0	(0)	1,117,302	(926,375)	(121,593)	0	(1,047,968)	190,927
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	8,245,840	3,347,556	197,001	11,790,397	(2,975,591)	(813,310)	0	(3,788,901)	5,270,249
1830	Poles, Towers and Fixtures	12,652,485	3,034,923	0	15,687,408	(5,102,333)	(1,360,230)	0	(6,462,563)	7,550,152
1835	Overhead Conductors and Devices	9,341,907	2,005,660	0	11,347,568	(3,923,802)	(999,285)	0	(4,923,087)	5,418,105
1840	Underground Conduit	10,342,401	3,577,829	(0)	13,920,230	(2,941,611)	(1,253,048)	0	(4,194,659)	7,400,790
1845	Underground Conductors and Devices	10,950,253	1,521,857	(0)	12,472,110	(5,061,629)	(1,117,467)	0	(6,179,096)	5,888,624
1850	Line Transformers	19,926,454	4,195,091	(41,354)	24,080,191	(7,967,378)	(2,077,086)	35,151	(10,009,313)	11,959,076
1855	Services	15,236,477	1,229,601	(0)	16,466,078	(7,528,456)	(1,471,627)	0	(9,000,083)	7,708,021
1860	Meters	4,253,197	868,579	(60,000)	5,061,776	(1,980,395)	(460,142)	0	(2,440,537)	2,272,802
1905	Land	182,215	0	(0)	182,215	0	0	0	0	182,215
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	5,461,332	7,017	(0)	5,468,349	(1,452,800)	(274,235)	0	(1,727,035)	4,008,532
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	749,965	75,675	(0)	825,640	(631,513)	(68,216)	0	(699,729)	118,452
1920	Computer Equipment - Hardware	848,203	106,644	0	954,847	(689,199)	(174,383)	0	(863,582)	159,004
1925	Computer Software	719,966	270,765	(0)	990,731	(646,151)	(145,362)	0	(791,513)	73,815
1930	Transportation Equipment	0	0	0	0	0	0	0	0	0
1935	Stores Equipment	56,187	0	(0)	56,187	(56,187)	0	0	(56,187)	0
1940	Tools, Shop and Garage Equipment	0	4,284	0	4,284	0	(856)	0	(856)	0
1945	Measurement and Testing Equipment	0	20,903	0	20,903	0	(4,180)	0	(4,180)	0
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	78,103	0	0	78,103	(65,318)	(7,872)	0	(73,190)	12,785
1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
1965	Water Heater Rental Units	0	0	0	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	1,453,734	518,131	0	1,971,865	(698,735)	(304,496)	0	(1,003,231)	754,999
1985	Sentinel Lighting Rental Units	24,495			24,495	(24,101)	(203)	0	(24,304)	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants - Credit	(9,376,247)	(6,508,322)	(0)	(15,884,569)	815,868	1,390,579	0	2,206,447	(8,560,379)
2005	Property Under Capital Leases	0	0	0	0	0	0	0	0	0
	TOTAL	**92,515,509**	**14,327,553**	**77,309**	**106,920,371**	**(41,855,706)**	**(9,263,012)**	**35,151**	**(51,083,567)**	**50,659,409**

Schedule 4-2: For the Year Ending December 31, 2007

Fixed Asset Continuity Schedule
as at December 31, 2007

		Cost				Accumulated Depreciation				
OEB	Description	2007 Opening Balance	Additions	Disposals	Closing Balance	2007 Opening Balance	Amortization Expense	Disposals	Closing Balance	Net Book Value
1805	Land	245,786	0	0	245,786	0	0	0	0	0
1806	Land Rights	38,477	0	(9,169)	29,308	0	(9,169)	9,169	0	245,786
1808	Buildings and Fixtures	1,117,302	0	0	1,117,302	(1,047,968)	(48,637)	0	(1,096,605)	29,308
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	20,697
1815	Transformer Station Equipment - Normally Primary above 50 kV	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	11,790,397	638,866	0	12,429,263	(3,788,901)	(392,135)	0	(4,181,036)	0
1830	Poles, Towers and Fixtures	15,687,408	2,694,509	(0)	18,381,917	(6,462,563)	(678,643)	0	(7,141,206)	8,248,227
1835	Overhead Conductors and Devices	11,347,568	1,224,446	0	12,572,014	(4,923,087)	(462,343)	0	(5,385,430)	11,240,711
1840	Underground Conduit	13,920,230	884,148	0	14,804,378	(4,194,659)	(580,004)	0	(4,774,663)	7,186,584
1845	Underground Conductors and Devices	12,472,110	1,201,144	0	13,673,254	(6,179,096)	(528,810)	0	(6,707,906)	10,029,715
1850	Line Transformers	24,080,191	1,033,613	(16,124)	25,097,680	(10,009,313)	(924,808)	13,516	(10,920,605)	6,965,348
1855	Services	16,466,078	419,479	0	16,885,557	(9,000,083)	(616,611)	0	(9,616,694)	14,177,075
1860	Meters	5,061,776	153,914	0	5,215,690	(2,440,537)	(172,266)	0	(2,612,803)	7,268,863
1905	Land	182,215	0	0	182,215	0	0	0	0	2,602,887
1906	Land Rights	0	0	0	0	0	0	0	0	182,215
1908	Buildings and Fixtures	5,468,349	0	0	5,468,349	(1,727,035)	(109,722)	0	(1,836,757)	0
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	3,631,592
1915	Office Furniture and Equipment	825,640	38,128	0	863,768	(699,729)	(28,915)	0	(728,644)	0
1920	Computer Equipment - Hardware	954,847	100,558	(0)	1,055,405	(863,582)	(61,463)	0	(925,045)	135,124
1925	Computer Software	990,731	88,225	(0)	1,078,956	(791,513)	(79,289)	0	(870,802)	130,360
1930	Transportation Equipment	0	0	0	0	0	0	0	0	208,154
1935	Stores Equipment	56,187	0	0	56,187	(56,187)	0	0	(56,187)	0
1940	Tools, Shop and Garage Equipment	4,284	0	0	4,284	(856)	(428)	0	(1,284)	(0)
1945	Measurement and Testing Equipment	20,903	0	0	20,903	(4,180)	(2,090)	0	(6,270)	3,000
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	14,633
1955	Communication Equipment	78,103	0	0	78,103	(73,190)	(2,632)	0	(75,822)	0
1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	2,281
1965	Water Heater Rental Units	0	0	0	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	1,971,865	94,910	0	2,066,775	(1,003,231)	(136,749)	0	(1,139,980)	0
1985	Sentinel Lighting Rental Units	24,495			24,495	(24,304)	(81)	0	(24,385)	926,795
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants - Credit	(15,884,569)	(1,771,437)	0	(17,656,006)	2,206,447	706,239	0	2,912,686	0
2005	Property Under Capital Leases	0	0	0	0	0	0	0	0	(14,743,320)
	TOTAL	**106,920,371**	**6,800,504**	**(25,292)**	**113,695,583**	**(51,083,567)**	**(4,128,556)**	**22,685**	**(55,189,438)**	**58,506,035**

Schedule 4-3: For the Year Ending December 31, 2008

Fixed Asset Continuity Schedule
as at December 31, 2008

		Cost				Accumulated Depreciation				
OEB	**Description**	**2008 Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**2008 Opening Balance**	**Amortization Expense**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	245,786	0	0	245,786	0	0	0	0	0
1806	Land Rights	29,308	0	(9,169)	20,140	0	(9,169)	9,169	0	245,786
1808	Buildings and Fixtures	1,117,302	0	0	1,117,302	(1,096,605)	(4,115)	0	(1,100,720)	20,140
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	16,582
1815	Transformer Station Equipment - Normally Primary above 50 kV	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	12,429,263	2,269,751	0	14,699,014	(4,181,036)	(467,793)	0	(4,648,829)	0
1830	Poles, Towers and Fixtures	18,381,917	1,996,336	0	20,378,253	(7,141,206)	(749,008)	0	(7,890,214)	10,050,185
1835	Overhead Conductors and Devices	12,572,014	984,097	(0)	13,556,111	(5,385,430)	(479,632)	0	(5,865,062)	12,488,039
1840	Underground Conduit	14,804,378	1,381,255	(0)	16,185,633	(4,774,663)	(649,328)	0	(5,423,991)	7,691,049
1845	Underground Conductors and Devices	13,673,254	716,256	(0)	14,389,510	(6,707,906)	(565,630)	0	(7,273,536)	10,761,642
1850	Line Transformers	25,097,680	2,067,427	(35,167)	27,129,940	(10,920,605)	(1,005,113)	26,510	(11,899,208)	7,115,974
1855	Services	16,885,557	554,849	1	17,440,407	(9,616,694)	(634,439)	0	(10,251,133)	15,230,732
1860	Meters	5,215,690	320,475	(0)	5,536,165	(2,612,803)	(192,367)	0	(2,805,170)	7,189,274
1905	Land	182,215	0	0	182,215	0	0	0	0	2,730,995
1906	Land Rights	0	0	0	0	0	0	0	0	182,215
1908	Buildings and Fixtures	5,468,349	0	0	5,468,349	(1,836,757)	(109,722)	0	(1,946,479)	0
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	3,521,870
1915	Office Furniture and Equipment	863,768	30,769	0	894,537	(728,644)	(27,764)	0	(756,408)	0
1920	Computer Equipment - Hardware	1,055,405	154,190	0	1,209,595	(925,045)	(80,223)	0	(1,005,268)	138,129
1925	Computer Software	1,078,956	228,457	0	1,307,413	(870,802)	(119,230)	0	(990,032)	204,327
1930	Transportation Equipment	0	0	0	0	0	0	0	0	317,381
1935	Stores Equipment	56,187	0	0	56,187	(56,187)	0	0	(56,187)	0
1940	Tools, Shop and Garage Equipment	4,284	0	0	4,284	(1,284)	(428)	0	(1,712)	(0)
1945	Measurement and Testing Equipment	20,903	0	0	20,903	(6,270)	(2,090)	0	(8,360)	2,572
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	12,543
1955	Communication Equipment	78,103	0	0	78,103	(75,822)	(1,635)	0	(77,457)	0
1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	646
1965	Water Heater Rental Units	0	0	0	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	2,066,775	39,201	(0)	2,105,976	(1,139,980)	(139,290)	0	(1,279,270)	0
1985	Sentinel Lighting Rental Units	24,495			24,495	(24,385)	(55)	0	(24,440)	826,706
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants - Credit	(17,656,006)	(3,238,879)	0	(20,894,884)	2,912,686	835,794	0	3,748,480	0
2005	Property Under Capital Leases	0	0	0	0	0	0	0	0	(17,146,404)
	TOTAL	**113,695,583**	**7,504,184**	**(44,335)**	**121,155,432**	**(55,189,438)**	**(4,401,237)**	**35,679**	**(59,554,996)**	**61,600,381**

Schedule 4-4: For the Year Ending December 31, 2009

Fixed Asset Continuity Schedule
as at December 31, 2009

		Cost				Accumulated Depreciation				
OEB	**Description**	**2009 Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**2009 Opening Balance**	**Amortization Expense**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	245,786	0	0	245,786	0	0	0	0	0
1806	Land Rights	20,140	0	(9,169)	10,971	0	0	0	0	245,786
1808	Buildings and Fixtures	1,117,302	0	0	1,117,302	(1,100,720)	(4,115)	0	(1,104,835)	10,971
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	12,467
1815	Transformer Station Equipment - Normally Primary above 50 kV	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	14,699,014	1,922,000	0	16,621,014	(4,648,829)	(531,860)	0	(5,180,689)	0
1830	Poles, Towers and Fixtures	20,378,253	1,080,000	0	21,458,253	(7,890,214)	(792,208)	0	(8,682,422)	11,440,325
1835	Overhead Conductors and Devices	13,556,111	432,000	0	13,988,111	(5,865,062)	(496,912)	0	(6,361,974)	12,775,831
1840	Underground Conduit	16,185,633	580,000	0	16,765,633	(5,423,991)	(672,528)	0	(6,096,519)	7,626,137
1845	Underground Conductors and Devices	14,389,510	411,000	0	14,800,510	(7,273,536)	(569,676)	0	(7,843,212)	10,669,114
1850	Line Transformers	27,129,940	1,288,000	(23,000)	28,394,940	(11,899,208)	(1,056,633)	20,000	(12,935,841)	6,957,298
1855	Services	17,440,407	287,000	0	17,727,407	(10,251,133)	(645,919)	0	(10,897,052)	15,459,099
1860	Meters	5,536,165	120,000	0	5,656,165	(2,805,170)	(197,167)	0	(3,002,337)	6,830,355
1905	Land	182,215	0	0	182,215	0	0	0	0	2,653,828
1906	Land Rights	0	0	0	0	0	0	0	0	182,215
1908	Buildings and Fixtures	5,468,349	15,000	0	5,483,349	(1,946,479)	(109,777)	0	(2,056,256)	0
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	3,427,093
1915	Office Furniture and Equipment	894,537	10,000	0	904,537	(756,408)	(28,635)	0	(785,043)	0
1920	Computer Equipment - Hardware	1,209,595	95,000	0	1,304,595	(1,005,268)	(83,323)	0	(1,088,591)	119,494
1925	Computer Software	1,307,413	185,000	0	1,492,413	(990,032)	(145,557)	0	(1,135,589)	216,004
1930	Transportation Equipment	0	0	0	0	0	0	0	0	356,824
1935	Stores Equipment	56,187	0	0	56,187	(56,187)	0	0	(56,187)	0
1940	Tools, Shop and Garage Equipment	4,284	0	0	4,284	(1,712)	(428)	0	(2,140)	(0)
1945	Measurement and Testing Equipment	20,903	0	0	20,903	(8,360)	(2,090)	0	(10,450)	2,144
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	10,453
1955	Communication Equipment	78,103	0	0	78,103	(77,457)	(646)	0	(78,103)	0
1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
1965	Water Heater Rental Units	0	0	0	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	2,105,976	41,000	0	2,146,976	(1,279,270)	(124,100)	0	(1,403,370)	0
1985	Sentinel Lighting Rental Units	24,495		(24,495)	(0)	(24,440)	(55)	24,495	0	743,606
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants - Credit	(20,894,884)	(1,083,000)	0	(21,977,884)	3,748,480	879,114	0	4,627,594	0
2005	Property Under Capital Leases	0	0	0	0	0	0	0	0	(17,350,290)
	TOTAL	**121,155,432**	**5,383,000**	**(56,664)**	**126,481,768**	**(59,554,996)**	**(4,582,515)**	**44,495**	**(64,093,016)**	**62,388,752**

Schedule 4-5: For the Year Ending December 31, 2010

Fixed Asset Continuity Schedule
as at December 31, 2010

OEB	Description	Cost: 2010 Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: 2010 Opening Balance	Accumulated Depreciation: Amortization Expense	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
1805	Land	245,786	0	0	245,786	0	0	0	0	0
1806	Land Rights	10,971	0	0	10,971	0	0	0	0	245,786
1808	Buildings and Fixtures	1,117,302	0	0	1,117,302	(1,104,835)	(4,115)	0	(1,108,950)	10,971
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	8,352
1815	Transformer Station Equipment - Normally Primary above 50 kV	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	16,621,014	1,381,000	0	18,002,014	(5,180,689)	(577,893)	0	(5,758,582)	0
1830	Poles, Towers and Fixtures	21,458,253	3,996,000	0	25,454,253	(8,682,422)	(952,048)	0	(9,634,470)	12,243,432
1835	Overhead Conductors and Devices	13,988,111	1,044,000	0	15,032,111	(6,361,974)	(538,672)	0	(6,900,646)	15,819,783
1840	Underground Conduit	16,765,633	748,000	0	17,513,633	(6,096,519)	(702,448)	0	(6,798,967)	8,131,465
1845	Underground Conductors and Devices	14,800,510	616,000	0	15,416,510	(7,843,212)	(556,198)	0	(8,399,410)	10,714,666
1850	Line Transformers	28,394,940	1,518,000	(23,000)	29,889,940	(12,935,841)	(1,117,353)	0	(14,053,194)	7,017,100
1855	Services	17,727,407	1,030,000	0	18,757,407	(10,897,052)	(735,005)	0	(11,632,057)	15,836,746
1860	Meters	5,656,165	132,000	0	5,788,165	(3,002,337)	(202,447)	0	(3,204,784)	7,125,350
1905	Land	182,215	0	0	182,215	0	0	0	0	2,583,381
1906	Land Rights	0	0	0	0	0	0	0	0	182,215
1908	Buildings and Fixtures	5,483,349	157,000	0	5,640,349	(2,056,256)	(111,854)	0	(2,168,110)	0
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	3,472,239
1915	Office Furniture and Equipment	904,537	10,000	0	914,537	(785,043)	(26,681)	0	(811,724)	0
1920	Computer Equipment - Hardware	1,304,595	86,000	0	1,390,595	(1,088,591)	(95,433)	0	(1,184,024)	102,813
1925	Computer Software	1,492,413	204,000	0	1,696,413	(1,135,589)	(177,595)	0	(1,313,184)	206,571
1930	Transportation Equipment	0	0	0	0	0	0	0	0	383,229
1935	Stores Equipment	56,187	0	0	56,187	(56,187)	0	0	(56,187)	0
1940	Tools, Shop and Garage Equipment	4,284	0	0	4,284	(2,140)	(428)	0	(2,568)	(0)
1945	Measurement and Testing Equipment	20,903	0	0	20,903	(10,450)	(2,090)	0	(12,540)	1,716
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	8,363
1955	Communication Equipment	78,103	0	0	78,103	(78,103)	0	0	(78,103)	0
1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
1965	Water Heater Rental Units	0	0	0	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	2,146,976	80,000	0	2,226,976	(1,403,370)	(111,965)	0	(1,515,335)	0
1985	Sentinel Lighting Rental Units	(0)			(0)					
1990	Other Tangible Property	0	0	0	0	0	0	0	0	711,641
1995	Contributions and Grants - Credit	(21,977,884)	(2,593,000)	0	(24,570,884)	4,627,594	982,834	0	5,610,428	0
2005	Property Under Capital Leases	0	0	0	0	0	0	0	0	(18,960,456)
	TOTAL	**126,481,768**	**8,409,000**	**(23,000)**	**134,867,768**	**(64,093,016)**	**(4,929,391)**	**0**	**(69,022,407)**	**65,845,361**

SERVICE QUALITY – HISTORICAL DATA

The OEB defines the key performance indicators in Chapter 7 of the Distribution System Code "Electricity Service Quality Requirements". The "standard" defined by the OEB is the expected minimum performance number. Currently there are no minimum performance standards codified for system reliability, although the OEB has indicated their intention to do so in the future once sufficiently reliable data is collected. With respect to system reliability, data filed for "Reporting and Record Keeping" (RRR), the standard reference point is within the range of 3 years of historical performance.

The table below lists the historical 3 years of data for Service Reliability Indices:

Measure	Description	Standard	2006	2007	2008
New Connection – Low Voltage	% connected within 5 days	90%	100.0%	100.0%	100.0%
New Connection – High Voltage	% connected within 10 days	90%	100.0%	100.0%	100.0%
Underground Cable Locates	% located within 5 days	90%	95.24%	95.0%	94.0%
Telephone Accessibility	% answered within 30 sec.	65%	94.69%	94.9%	90.6%
Appointments Met	% kept as scheduled	90%	100.0%	100.0%	100.0%
Written Responses to Inquiries	% responded within 10 days	80%	100.0%	100.0%	100.0%
Emergency Response - Urban	% responded to within 60 min	80%	100.0%	100.0%	100.0%
Emergency Response – Rural	% responded to within 120 min	80%	100.0%	100.0%	100.0%
SAIDI	Including failure of supply		0.79	0.83	0.24
SAIFI	Including failure of supply		0.58	1.05	0.43
CAIDI	Including failure of supply		1.36	0.79	0.57
SAIDI	Excluding failure of supply		n/a	0.45	0.24
SAIFI	Excluding failure of supply		n/a	0.79	0.43
CAIDI	Excluding failure of supply		n/a	0.57	0.57

Whitby Hydro acknowledges the importance of key service quality indicators to its customers and strives to maintain them at sufficiently high levels. These indicators are tracked and reported to the OEB through RRR filings on an annual basis and are reviewed by the management team to ensure levels are maintained above the required standards and to address any issues or concerns that may impede this objective.

Whitby Hydro has consistently exceeded the service quality standards over the past 3 years and plans to continue to focus on keeping the required measurements at the appropriate levels in 2009 and 2010. It should be noted that the OEB recently reviewed existing standards and added new measurement indicators beginning in 2009. Whitby Hydro's management team was made aware of these requirements in December 2008 to ensure that any new requirements and standards are understood and processes adjusted for tracking going forward.

With respect to system reliability, Whitby Hydro had concerns in the past with respect to the impacts of supply related failures on these measurements. The OEB has in recent years, acknowledged this concern and since 2007, requested that distributors report these measurements both including and excluding supply related failures. This additional information gives preferred comparisons, as they allow those analyzing the results to measure indices which are more reflective of the reliability of the distributor's system and gives improved comparability for those distributors that are embedded or partially embedded (like Whitby Hydro). From 2006 to 2008, Whitby Hydro has maintained system reliability within the prior 3 years historical data on a consistent basis.

EXHIBIT 3
OPERATING REVENUE

OVERVIEW OF OPERATING REVENUE

This Exhibit provides the details of Whitby Hydro's Operating Revenue for the 2006 Board Approved, 2006 – 2008 Actuals, the 2009 Bridge Year and 2010 Test Year, including a summary of the annual variances.

The Exhibit also provides details of the Load Forecast including methodology and comparisons of the customer count, consumption and demand data by customer class for the same time periods on both a weather actual and weather normalized basis (if relevant).

A summary of Operating Revenue is presented in Table 3-1. The Total Operating Revenue reconciles to the sum of all USoA accounts in the following account groupings:

- 3050 – Revenue From Services (accounts 4080 – 4090)
- 3100 – Other Operating Revenues (accounts 4205 – 4245)
- 3150 - Other Income and Deductions (accounts 4305 – 4398)
- 3200 – Investment Income (accounts 4405 – 4415)

Commodity revenue has been excluded from any data or analysis.

Distribution Revenue:

Distribution revenue in this application includes fixed charge revenues from monthly service charges as well as variable charge revenues which are based on consumption and demand billing determinants.

In Table 3-1, distribution revenue excludes recoveries for low voltage costs and does not include revenues from smart meter rate adders; CDM; or regulatory asset recovery rate riders. Transformer allowances are represented on a separate line in the table. LRAM recoveries are included in the other adjustments line on Table 3-1.

Other Revenue:

Other Revenue includes Specific Service Charges, Late Payment Charges, Other Distribution Revenue and Other Income and Expenses on the basis of the account groupings defined in the Board's Filing Requirements (appendix 2-D). In Table 3-1, the section for other revenue has already been adjusted to remove the following revenue that should not be included as a revenue offset:

- Interest from Regulatory Assets
- Interest Income from Customer Deposits
- Interest Income from PILs
- Non-Utility Revenue (OPA programs)
- Non-Utility Expense (OPA programs)

Revenue from these sources has been included in the “Other Adjustment” line in order to reconcile to the trial balance amounts.

1 **Table 3-1: Summary of Operating Revenue**

	2006 Board Approved	2006 Actual	2006 Actual vs. 2006 Board Approved	2007 Actual	2007 Actual vs. 2006 Actual	2008 Actual	2008 Actual vs. 2007 Actual	2009 Bridge	2009 Bridge vs. 2008 Actual	2010 Test	2010 Test vs. 2009 Bridge
Residential	10,690,196	11,469,119	778,923	11,552,429	83,310	11,948,504	396,075	11,910,840	(37,664)	12,913,963	1,003,123
GS<50	1,688,237	1,667,802	(20,435)	1,698,008	30,206	1,732,685	34,677	1,732,713	28	1,951,368	218,655
GS>50	3,725,591	4,197,112	471,521	4,073,300	(123,812)	4,072,725	(575)	4,010,108	(62,617)	4,831,270	821,162
USL	87,007	104,106	17,099	123,489	19,383	124,818	1,329	126,031	1,213	122,295	(3,736)
Sentinel Lights	3,398	1,516	(1,882)	1,309	(207)	1,400	91	2,469	1,069	3,213	743
Streetlights	210,390	232,838	22,448	230,335	(2,503)	230,428	93	235,277	4,849	327,907	92,631
Distribution Revenue	**16,404,819**	**17,672,493**	**1,267,674**	**17,678,870**	**6,377**	**18,110,560**	**431,690**	**18,017,438**	**(93,122)**	**20,150,016**	**2,132,578**
			7.7%		**0.0%**		**2.4%**		**-0.5%**		**11.8%**
Transformer Ownership Allowance	(259,138)	(331,142)	(72,004)	(292,396)	38,746	(284,631)	7,765	(292,015)	(7,384)	(293,570)	(1,555)
Other Revenue											
Specific Service Charges	196,518	136,946	(59,572)	154,281	17,335	249,082	94,801	154,835	(94,247)	157,835	3,000
Late Payment	275,846	297,895	22,049	343,757	45,862	321,056	(22,701)	375,000	53,944	321,000	(54,000)
Other Distribution Revenue	263,580	262,550	(1,030)	300,716	38,167	312,425	11,708	345,091	32,666	333,908	(11,183)
Other Income and Expense	158,777	220,167	61,390	304,195	84,028	251,843	(52,352)	88,000	(163,843)	78,000	(10,000)
Total Other Revenue (Offset)	**894,721**	**917,557**	**22,836**	**1,102,950**	**185,392**	**1,134,406**	**31,456**	**962,926**	**(171,480)**	**890,743**	**(72,183)**
Total Operating Revenue	**17,040,402**	**18,258,908**	**1,218,506**	**18,489,424**	**230,515**	**18,960,335**	**470,911**	**18,688,349**	**(271,986)**	**20,747,188**	**2,058,839**
Other Adjustments to balance to Trial Balance	**487,014**	**737,067**	**250,053**	**596,718**	**(140,349)**	**(163,013)**	**(759,731)**	**(12,202)**	**150,811**	**(1,516)**	**10,686**
Total Operating Revenue (including adjustments)	**17,527,416**	**18,995,975**	**1,468,559**	**19,086,142**	**90,166**	**18,797,322**	**(288,820)**	**18,676,147**	**(121,175)**	**20,745,672**	**2,069,525**
			8.4%		**0.5%**		**-1.5%**		**-0.6%**		**11.1%**

VARIANCE ANALYSIS ON OPERATING REVENUE

Whitby Hydro's 2009 Distribution Revenue has been calculated using its most recently approved rates (Decision and Order EB-2008-0251 dated March 11, 2009) and estimated number of customers and consumption. To allow for consistency in this analysis, Smart Meter rate adders and Low Voltage cost recoveries have been excluded from the calculations for 2009. In addition, historical years exclude any CDM and Regulatory Asset revenue recoveries. In order to tie to the reported regulatory revenue on the trial balance for the identified USoA groupings, an adjustment has been included for reconciliation purposes only.

Further details regarding Other Revenue can be found on Tables 3-6 to 3-10.

2006 Board Approved:

Whitby Hydro's 2006 Board approved Distribution Revenue was forecasted to be $16.4M and Total Revenue was estimated at $17.5M.

2006 Actual:

Whitby Hydro's Distribution Revenue in the 2006 fiscal year was $17.7M, 7.7% higher than the 2006 Board Approved. The increase is due to customer growth and excess CDM collected related to third tranche offset by only 8 months of the Board Approved 2006 Revenue Requirement. Total Revenue was 19.0M which represents a 8.4% increase from the 2006 Board Approved amount. Other Revenue was 102.6% of the 2006 Board Approved figure.

2007 Actual:

Whitby Hydro's 2007 distribution revenue was $17.7M, which was virtually flat compared to 2006 Actuals. There were revenue increases due to customer growth and a full year of 2006 Approved Revenue Requirement but this was offset by the absence of excess CDM collected. Total Revenue of $19.1M was also in line with 2006 Actuals. Other Revenue was $0.2M above the levels in 2006.

2008 Actual:

Whitby Hydro's 2008 Distribution Revenue of $18.1M represented a 2.4% increase over 2007 Actuals due to customer growth. Total Revenue of $18.8M represents a 1.5% decrease over 2007 Actuals. Other Revenue was virtually flat to 2008 levels.

2009 Bridge Year:

Whitby Hydro's Distribution Revenue is forecasted to be $18.0 M (based on Board approved 2009 rates with Smart Meter rate adders and Low Voltage cost recoveries removed and a weather normalized load forecast). Total Revenue is projected to be $18.7M. Other Revenue is projected to decline by $0.2M largely due to reduced growth levels which impact specific service charge revenues as well as an adjustment to miscellaneous revenue.

Comparison to 2008 Actual:

The Distribution Revenue is forecasted to decrease by $0.1M (-0.5%). While weather normalized loads in the general service classes are declining, approximately 50% of the Distribution Revenue is based on monthly service charges which assist in maintaining some revenue stability. The declines in load are partially offset by the increase in rates from 2008 to 2009. Other Revenue has declined largely due to reduced growth levels which impact specific service charge revenues as well as an adjustment to miscellaneous revenue.

2010 Test Year:

Whitby Hydro's Distribution Revenue is forecast to be $20.2M. Total Revenue is forecast to be $20.9M based on the 2010 revenue requirement as shown in Exhibit 6. Total revenue includes $0.2M for proposed LRAM recoveries in the test year. Other Revenue is forecasted at $0.9M.

Comparison to 2009 Bridge Year:

The Distribution Revenue is forecasted to increase by $2.1M (11.8%). This increase is a result of increased revenues required through the Revenue Deficiency determination of $2.0M.

LOAD FORECASTING

Whitby Hydro engaged resources from Elenchus Research Associates (ERA) to assist in the preparation of a weather normalized load forecast for 2009 and 2010. For the purpose of developing the load forecast, 10 years worth of monthly wholesale kWh was gathered. In addition, historical data by customer class (kWh, kW, customer count/connections) was compiled for the period January 2002 – September 2009 inclusive.

OVERVIEW OF METHODOLOGY

ERA explored several approaches to developing a weather normalized forecast by customer class before deciding to use a multiple regression analysis. Specifically, a forecasting approach based on customer class data was found to be problematic given the data limitations associated with customer billing cycles. Whitby Hydro's current customer billing consumption readings do not match a calendar month and this is compounded by bi-monthly billing cycles for residential customers. The NAC approach was also investigated and found to be limited by its inability to adequately incorporate recent trends in consumption that have occurred in the Whitby Hydro service area largely as a result of economic conditions.

Ultimately ERA selected a multiple regression analysis utilizing ten years of monthly wholesale data which included variables for weather, economic activity (employment) and other explanatory variables. The class specific forecasts were then developed using recent historical proportions for weather sensitive classes and use per customer/connection for non-weather sensitive classes. The derivation of kW forecasts involved annual ratios of class kW to kWh. A more fulsome description of the methodology and related calculations can be found in ERA's load forecast report entitled "Weather Normalized Distribution System Load Forecast – 2010 Test Year" dated November 3, 2009 which is included as Attachment 3-1.

When supplying historical data to ERA, Whitby Hydro noted that some movement of customer accounts between customer classifications has occurred during the past five years. In order to improve the accuracy of the consumption data, ERA recommended that billing information be reviewed and restated to align the historical data with the current customer classification of each customer account. Whitby Hydro engaged the CIS provider (Harris North Star) to develop a program to track information for accounts that had different customer classifications over the 2002-2008 time-frame as compared to their current customer classifications. Final reports based on the tested results were provided early in 2009. This data was analyzed and adjusted where necessary to ensure that historic consumption reflects the customer classifications as they existed in February 2009.

FORECAST OF FUTURE CUSTOMER GROWTH BY CLASS

Customer count forecasts were developed by Whitby Hydro using an assessment of 2009 customer growth (year-to-date) and expected attachments due to new subdivision development, economic outlook for the area and historical trends by customer class. The specific approach used for each customer class was as follows:

RESIDENTIAL

Over the past 9 years (1999-2008) The Town of Whitby has experienced a very significant growth (51.3 %) in the residential sector, representing an annual growth rate of 5.7%. In 2008, residential housing construction started to taper off and growth was only 2.5 % and so far in 2009, housing starts have been at a 10 year low with a growth forecast of 0.7%.

Forecasting future residential development has proved to be a challenge in the current economic downturn as builders no longer build homes on speculation. Given Whitby's proximity to Oshawa and the impact of the closing of significant vehicle production at General Motors and associated automotive feeder companies throughout the region, residential builders have confirmed that housing starts will be initiated only on demand.

Current economic conditions are proving to stall housing starts through 2009 and it is not expected to increase at any significant rate through 2010. Accordingly, housing starts are forecast to be 0.7% in 2009 and 1.0% in 2010.

In determining the future number of residential lots to be connected annually the following is taken into account;

- Number of subdivisions that have been energized previously and total number of vacant lots.
- Proposed subdivisions to be constructed and anticipated date of energization.
- History of lots connected in previous years.
- Information received from Developers and/or Builders.
- Building permits issued by the Town of Whitby.

Based on the assessment of the information gathered above, the total estimated residential lots to be connected for Year 2009 is 275 lots and Year 2010 is 385 lots.

For Year 2009 the following data was used to determine the estimated residential customer counts:

- There are a total of 876 lots remaining to be connected in energized subdivisions at the end of 2008. There were 170 lots connected to the end of August 2009 and through discussions with builders it is estimated that an additional 84 of these lots will be connected by the end of 2009.
- In 2009, four smaller new subdivisions are forecast to be connected yielding an additional 150 lots. From discussions with developers and builders Whitby Hydro forecasts that only 21 lots will be connected by the end of 2009.
- For Year 2009 there was a loss of 37 residential customers in compliance with the OEB policy regarding long term load transfer customers. These customers were transferred to their physical distributor.

The aggregate of existing and new lots to be connected less the loss of existing load transfer customers brings the total to 238 net customer additions for 2009.

For Year 2010 the following data was used to determine the estimated total of 385 lots;

- There are a total of 751 lots remaining to be connected in energized subdivisions. In discussion with builders it is estimated that 330 lots will be connected.
- There are a total of 1,201 proposed subdivision lots to be constructed in 2010 based on current plans and applications in process at the Municipality. It is estimated that a total of 55 lots will energized and residential services connected based on discussions with builders.

The aggregate of existing and proposed new lots brings the total forecast for 2010 to 385 new residential connections.

GENERAL SERVICE

The impact of the closing of significant vehicle production at General Motors and associated automotive feeder companies throughout the region has had an adverse effect on commercial activity in Whitby. This change along with the overall impact of an economic recession has resulted in a noticeable flat and in some cases downward trend for General Service classes whereby the limited new service activity has been more than offset by lost customers.

General Service Class Less than 50kW Demand

As of August 2009 only 8 new services were connected but 10 customers were lost in the same time period resulting in a net loss of 2 customers. There is some new service activity projected through to the end of 2009 however, the trending suggests that this will only result in a net addition for the year of 1, bringing the overall customer count to 1,909.

It is expected that the negative effects of the 2009 economic conditions will continue into 2010. There are currently 2 proposed connections identified for 2010. Although there could be further customer additions, it is anticipated that these will be offset by the continued, but slower trend of losing customers. This activity will result in a zero customer growth forecast, leaving the ending customer count unchanged at 1,909.

General Service Class Greater Than 50kW Demand

The lead time for connecting new customers in this class ranges from 6 to 9 months. As a result of this lead time, it takes greater time for this customer class to recover when there are customers lost due to a downturn in the economy. The year started with 431 customers in this class and as of August 2009, there has been a net increase of 2 customer additions, bringing the August count to 433. Based on the connection timing and experience, the forecast for 2009 will remain at 433, while the 2010 customer count is projected to increase by 3 to 436.

UNMETERED SCATTER LOAD CUSTOMER CLASS

There has been very little activity in this customer class in 2009. These customer connections consist mainly of bill board sign lights, bus shelters, cable TV amplifiers and municipal intersection signalization. Given that there is very little subdivision growth or building activity, there has not been a demand for this type of service connection. In addition, Whitby Hydro plans to meter more of these types of loads which would offset any expected growth in the customer count.

The bridge year started out with 390 service connections in the USL customer class. By the end of August 2009 there was one less connection; however, one additional connection is expected by the end of the year yielding no net change to the customer count in this class for 2009.

The forecast for 2010 is for one additional connection bringing the total connections in the USL customer class to 391.

SENTINEL LIGHTS

The customer forecast for the sentinel light class is based on the number of lights, which is the billing determinant used for rates. Whitby Hydro has made efforts to review sentinel light ownership/configuration of equipment and to encourage individual metering of these services. As a result, the number of sentinel lights has declined in 2009 to 37 (from 46), and in 2010 there are no new additions forecasted.

STREET LIGHT CONFIGURATION

Whitby Hydro is a well established electricity distribution company that was formed in 1903. As technology has changed over the years, so has the way in which Whitby Hydro conducts business and builds and services infrastructure. In this regard, Whitby Hydro has a number of configurations related to the manner in which street lights have been connected to Whitby Hydro's distribution system over time. These connections range from a single connection of a street light to an overhead transformer or secondary bus, to a large number of lights connected though a service pedestal in underground residential subdivisions requiring only one connection to a transformer.

All of streetlights now being designed and connected in new residential subdivisions allow as many as ten streetlights energized though a single connection to the distribution system.

As of December 2008, Whitby Hydro supplied 11,181 individual street lights owned and maintained by the Town of Whitby, through 3,538 connections to its distribution system. This yields a ratio of lights to connections of 3.2 to 1. This ratio will continue to increase as new underground serviced residential subdivisions are developed and older subdivisions undergo cable rehabilitation bringing older construction techniques up to present date standards.

The customer forecast for this class is reflective of the number of streetlights (lamps) as this is the billing determinant used for deriving rates. The total number of streetlights projected for 2009 and 2010 is primarily driven by the key factors influencing the residential forecast and takes into account new and proposed subdivisions, historical data and planning information from the Town of Whitby. This analysis has resulted in an overall forecast of 193 street light additions in 2009 and 207 in 2010.

ADDITIONAL FORECAST CONSIDERATIONS

KEY ACCOUNTS AND AUTO-RELATED CUSTOMERS

With the recent recession and its effect on the key accounts (including the auto and auto-related businesses), significant load reductions are expected for several key customers. To ensure that these downward trends do not go unrecognized, a review of these accounts has been undertaken and includes consumption and demand trends for the first months of 2009 as compared to the same period of time historically. The results are summarized as follows:

Historical Consumption for Key Account/Auto Related Customers

	2009	2008	2007	2006
kwh	33,198,562	46,440,546	51,131,489	53,519,969
% yearly change	-28.5%	-9.2%	-4.5%	
% over 4 years	-38.0%			
kw	72,816	88,905	97,300	99,420
% yearly change	-18.1%	-8.6%	-2.1%	
% over 4 years	-26.8%			
Number of Customers	7	7	7	7

CONSERVATION AND DEMAND MANAGEMENT

The Conservation and Demand Management (CDM) efforts by Whitby Hydro through third tranche funding, Ontario Power Authority (OPA) programs and other CDM efforts have served to support the overall conservation messages that the local, provincial and federal governments are directing to all residential customers and businesses in the community. Effects of conservation on customer load have been incorporated into the forecast solely by virtue of the forecasting methodology used.

VARIANCE ANALYSIS

Table 3-2 shows the customer count/connections, consumption and demand data for the individual customer classes on both a weather actual and a weather normalized basis for the 2006 Board Approved, 2006 – 2008 Actual Years, 2009 Bridge Year and 2010 Test Year.

The main driver of annual changes to weather normalized consumption and demand is customer counts/connections. Whitby Hydro's population growth has been significant over the past 9 years but has tapered off considerably in more recent years and is expected to be at a 10 year low in 2009 with no real significant changes in 2010.

The link between customer growth and consumption in the Residential class is very apparent over the 2006 to 2010 time period. While this general trend is expected to continue, the impact of

CDM on the Residential class becomes more evident in the 2008 and 2009 timeframe as consumption growth (while still positive), begins to track below the customer count growth.

While customer growth is also an important driver in the General Service class, the mix of customers within the class, and trends in the economy also play a role in consumption and demand levels. In addition, with several strong OPA CDM programs focused towards businesses (i.e. ERIP, Power Savings Blitz), many forward looking companies have begun to take advantage of incentives which help to reduce the costs associated with shifting to energy efficient technologies that will help reduce energy costs on a more long term basis.

The GS<50 class has seen levels of declining growth on a annual basis throughout the 2006 to projected 2010 timeframe. The impact of the economic conditions has become apparent in the 2009 projections (which incorporated actual data to September).

The GS>50 kW class is one that can be highly vulnerable to economic conditions. The customer growth rates over the 2006 – 2010 period display declining trends and the associated consumption and demand growth patterns are further compounded by the economic conditions. As noted, several key accounts have been harder hit due to their link to the automotive industry.

The USL customer class, Sentinel Lights and Street lighting classes have generally followed the growth patterns associated with number of connections.

Five years worth of historical data detailing average use per customer/connection has been provided in the ERA load forecast report (Table 11) for each individual customer class on both a weather actual and weather normalized basis. The results are consistent with the observations noted above.

Table 3-3 provides revenue on the basis of 2009 existing and 2010 proposed rates. For comparability purposes, LRAM recoveries have been excluded from the 2010 figures.

Table 3-2: Customer Count/Connections and Volumetric Comparisons

	2006 Board Approved	2006 Actual	2006 Actual vs. 2006 Board Approved	2007 Actual	2007 Actual vs. 2006 Actual	2008 Actual	2008 Actual vs. 2007 Actual	2009 Bridge	2009 Bridge vs. 2008 Actual	2010 Test	2010 Test vs. 2009 Bridge
Customer Count/Connections:											
Residential	32,611	34,506	1,895	35,300	794	36,030	730	36,615	585	36,927	312
GS<50	1,769	1,816	47	1,869	53	1,896	27	1,909	13	1,909	0
GS>50	380	405	25	412	7	423	11	432	9	435	3
USL	385	390	5	382	(8)	387	5	390	3	391	1
Sentinel Lights	79	50	(29)	47	(3)	46	(1)	42	(4)	37	(5)
Streetlights	10,228	10,740	512	11,012	272	11,123	111	11,278	155	11,495	217
Consumption (kWh):											
Residential		340,108,142		353,245,947	13,137,805	342,735,162	(10,510,785)				
GS<50		72,200,337		74,193,328	1,992,991	76,238,506	2,045,178				
GS>50		433,954,842		433,427,583	(527,259)	428,355,126	(5,072,457)				
USL		2,513,103		2,478,838	(34,265)	2,470,423	(8,415)				
Sentinel Lights		59,876		54,867	(5,009)	53,420	(1,447)				
Streetlights		8,538,442		8,671,157	132,715	8,809,935	138,778				
Consumption (kW):											
GS>50		996,785		997,932	1,147	998,516	584				
Sentinel Lights		166		151	(15)	148	(3)				
Streetlights		22,847		23,374	527	23,609	235				
WEATHER NORMALIZED											
Consumption (kWh):											
Residential	324,528,044	338,404,218	13,876,174	347,662,474	9,258,256	347,860,226	197,752	348,550,720	690,494	350,407,180	1,856,460
GS<50	75,025,059	71,838,617	(3,186,442)	73,020,614	1,181,997	77,378,533	4,357,919	74,752,298	(2,626,235)	75,150,446	398,148
GS>50	402,582,266	431,780,752	29,198,486	426,576,744	(5,204,008)	434,760,501	8,183,757	412,351,415	(22,409,086)	414,547,692	2,196,277
USL	2,403,352	2,513,103	109,751	2,478,838	(34,265)	2,470,423	(8,415)	2,487,431	17,008	2,493,809	6,378
Sentinel Lights	83,573	59,876	(23,697)	54,867	(5,009)	53,420	(1,447)	48,635	(4,785)	43,361	(5,274)
Streetlights	7,892,016	8,538,442	646,426	8,671,157	132,715	8,809,935	138,778	8,931,971	122,036	9,104,235	172,264
Consumption (kW):											
GS>50	918,335	991,791	73,456	982,158	(9,633)	1,013,447	31,289	961,211	(52,236)	966,330	5,119
Sentinel Lights	95	166	71	151	(15)	148	(3)	123	(25)	110	(13)
Streetlights	21,601	22,847	1,246	23,374	527	23,609	235	25,731	2,122	26,227	496

Note 1: Customer Count/Connection data is on an average basis.
Note 2: Historical Data has been re-aligned to match customer classifications as of Feb/09
Note 3: 2006 Board Approved adjusted to restate classification of Rogers kWh from GS<50 kW to USL class for comparability.

1 **Table 3-3: Revenue Calculations at Existing and Proposed Rates**

Customer Class Name	2009 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$16.7100	36,615	7,342,040	$0.0137	kWh	348,550,720	4,775,145	12,117,185
General Service Less Than 50 kW	$18.5100	1,909	424,027	$0.0181	kWh	74,752,298	1,353,017	1,777,044
General Service 50 to 4,999 kW	$191.3400	432	991,907	$3.3729	kW	961,211	3,242,069	4,233,975
Unmetered Scattered Load	$9.9700	390	46,660	$0.0325	kWh	2,487,431	80,842	127,501
Sentinel Lighting	$2.8700	42	1,446	$7.7629	kW	135	1,048	2,494
Street Lighting	$1.0400	11,278	140,749	$4.1309	kW	23,936	98,877	239,627
Gross Revenue (before Transformer Allowances)			8,946,829				9,550,997	18,497,826
Transformer Allowances				($0.6000)	kW	486,692	(292,015)	(292,015)
Total Revenue			**8,946,829**				**9,258,982**	**18,205,811**
Less: Pass-through amount embedded in distribution rates *							(480,388)	(480,388)
DISTRIBUTION REVENUE			**8,946,829**				**8,778,594**	**17,725,423**

Customer Class Name	2010 PROJECTED DISTRIBUTION REVENUE AT PROPOSED RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$17.6200	36,927	7,807,845	$0.0148	kWh	350,407,180	5,186,026	12,993,871
General Service Less Than 50 kW	$20.4400	1,909	468,240	$0.0200	kWh	75,150,446	1,503,009	1,971,248
General Service 50 to 4,999 kW	$191.3400	435	998,795	$4.0566	kW	966,330	3,920,014	4,918,809
Unmetered Scattered Load	$9.5900	391	44,996	$0.0312	kWh	2,493,809	77,807	122,803
Sentinel Lighting	$4.1900	37	1,860	$11.3413	kW	120	1,361	3,221
Street Lighting	$1.4000	11,478	192,830	$5.6149	kW	24,361	136,785	329,615
Gross Revenue (before Transformer Allowances)			9,514,566				10,825,002	20,339,568
Transformer Allowances				($0.6000)	kW	489,284	(293,570)	(293,570)
Total Revenue			**9,514,566**				**10,531,431**	**20,045,998**
Less: Pass-through amount embedded in distribution rates *							(203,590)	(203,590)
DISTRIBUTION REVENUE			**9,514,566**				**10,327,841**	**19,842,408**

TRANSFORMER OWNERSHIP ALLOWANCE

Whitby Hydro forecasts transformer ownership allowance credits totaling $292,015 in 2009 and $293,570 in 2010. Transformer allowance credits are proposed on the basis of $0.60 per kW for those customers who own their own transformer facilities.

While this credit applies to the GS> 50 kW class, not all customers are eligible for this credit. As a result, the forecast was based on a three year average of actual kW volumes for transformer allowances billed in the GS>50 kW class as a percentage of the total kW billed in that class. The supporting data is included in Table 3-4.

Table 3-4: 3 Year Average of kW Volumes for Transformer Allowance – GS>50 kW Class

Year	kW TRNALL	kW Billed	% of Billed
2006	551,903	996,785	55.40%
2007	487,326	997,932	48.80%
2008	476,341	998,516	47.70%
3 Year Average	**1,515,570**	**2,993,233**	**50.60%**

Table 3-5 shows the forecasted amounts for Transformer Allowances for 2009 and 2010 based on the methodology described.

Table 3-5: Forecast 2009 and 2010 for Transformer Allowances GS>50 kW Customer Class

Forecast 2009 and 2010 for Transformer Allowances
GS>50 kW Customer Class

	Normalized kW	kW TRNALL	Amount
2009F	961,211	486,692	$292,015
2010F	966,330	489,284	$293,570

OTHER REVENUE

Other Revenue includes the following categories: Specific Service Charges; Late Payment Charges; Other Distribution Revenue; and Other Income and Expenses. The forecast for Other Revenue is required to determine the revenue offset which is used to adjust the service revenue requirement to the base revenue requirement.

While the overall net impact of the change between the 2006 Board approved EDR and the 2010 proposed revenue offset is negligible, the key drivers of the change are more significant and can be summarized as follows:

Other Revenue - Revenue Offset Continuity 2006 Board Approved EDR - 2010 Test Year ($000s)		
2006 Board Approved EDR		$895
Late Payment Charges		$45
Interest Income		($81)
Volume - Cumulative Growth Based:		
- Rent from Electric Property	$28	
- Retail and Service Transactions	$22	
- SSS Admin Charge	$21	$71
Volume - Declining Growth Based:		
- Specific Service Charges		($39)
2010 Test Year		**$891**

As required by the Board's Filing Requirements, Appendix 2-D (Table 3-6) of the minimum filing requirements) provides a breakdown by USoA account for the historical years 2006 through to the bridge year (2009) and test year (2010). In addition, each revenue category has a separate table which highlights the key components which generate its revenue.

There are some elements which make up the Other Income and Expense category which are not included in the revenue offset as they represent income amounts that are excluded for regulatory purposes or owed to others. They are:

- Non-Utility Revenue and Expense (OPA programs)
- Interest Income (Regulatory Asset interest income/expense)

- Interest Income (from customer and retailer deposits and PILs interest)

The data provided in tables 3-6 and 3-10, include the above noted items for completeness, but the entries are identified separately so that these amounts can be removed to facilitate reconciliation to the revenue offset.

VARIANCE ANALYSIS ON OTHER REVENUE

SPECIFIC SERVICE CHARGES 4235

All of Whitby Hydro's current service charges were approved by the Board in the 2006 EDR using the standard rate table. Table 3-7 provides the details for each charge along with historic and projected revenues from 2006 to 2010. In the current application, Whitby Hydro proposes to continue to provide all of the previously approved services at the standard rates approved in 2006. Whitby Hydro also proposes to introduce one new specific service charge for 2010 – Legal Letter. This charge would apply the standard rate of $15 from the 2006 EDR table.

Easement Letter, Arrears and Legal Letter

In general the revenue for easement letters and arrears has been grouped together in a common account for financial reporting. The revenue for both of these service charges has dropped off largely due to the fact that customer hydro bill arrears can no longer be transferred to municipal property tax rolls. As a result, lawyers are no longer requesting arrears information when settling sale of property. As part of this application, Whitby Hydro is requesting the establishment of a specific service charge for Legal Letters ($15) which would be applied to all requests for legal letters. Subject to approval from the Board, Whitby Hydro would prefer to maintain the specific service charge for Easement Letters and Arrears so that they would be available should there be a requirement for these charges in the future.

Account Set Up Charge/Change of Occupancy

While there is a significant increase in this charge from 2006 to 2007, the increase is largely due to the full year impact of re-setting this rate to the standard dollar amount (an increase from $10 to $30) as part of the 2006 EDR. The 2009 revenue is declining slightly due to the reduced levels of new development and growth in Whitby. This rate of decline is not expected to change significantly in 2010.

Temporary Services

Temporary Service Revenue has been declining in tandem with the reduced levels of development and growth. It should be noted that while this work is tracked and charged to specific customers, the costs are also offset in this account. Based on current agreements, temporary service costs are expected to fully offset any revenue collected from customers (costs are shown as a separate line item in Table 3-7.

Other Specific Service Charges

Most other active specific service charges are trending at reasonably stable levels, and for the bridge year reflect 2009 activity (to August) with a forecast for the remainder of the 2009 calendar year. The 2010 projections for these charges are typically set at similar levels to those experienced and forecasted for 2009.

For those services that have had limited or no activity since 2006, Whitby Hydro would like to continue to maintain the current Board approved charges as part of the 2010 rate order. This will allow Whitby Hydro to monitor activity and apply the standard charges to the customers requiring these services. Even though the level of activity is expected to be limited, this approach is preferred as it is a more user specific approach to services provided.

Miscellaneous Revenue

While miscellaneous Revenue (account 4235) is normally aligned with specific service charges based on approved rates, there are some small items in this category that need to be reconciled. The amounts of $10,416 in 2006 and ($10,296) in 2007 are offsetting adjustments that were strictly timing related and have a minimal effect on net revenues. In 2008, an amount of approximately $80,000 was received for the purpose of maintaining customer plant (it has been noted that this non-recurring item should have been classified in 4390 Miscellaneous Non-Operating Revenue). The amounts projected for miscellaneous revenues in 2009 and 2010 are expected to be minimal.

LATE PAYMENT CHARGES – 4225

Late Payment Charges increased by 7.8% from 2006 to 2008 actuals, partially reflecting the start of the economic downturn. The impact of the current recession on late payment behaviour is even more apparent in the 2009 actuals to date. The higher incidence of late payments in 2009 has been reflected in the projected levels for the remainder of 2009 but has not been extended to the test year. Whitby Hydro expects that the incidence of late payments will be lower in the test year due to proposed OEB code changes that will allow customers to use deposits to pay off arrears and provide more time for customers to make bill payments. In addition, while it is difficult to predict the timing of the recovery, Whitby Hydro does not anticipated that the high late payment charges will continue at the same levels realized in 2009. Consequently, a 3 year average (2006-2008) has been used to project the levels of late payment charges for 2010 to eliminate the abnormal spike in 2009 that is not expected to be sustained going forward.

Table 3-8 shows the historical and projected levels from 2006 to 2010.

OTHER DISTRIBUTION REVENUES

Other Distribution Revenues includes Retailer Service Charges, Retail Service Transaction Requests and the Standard Supply Service (SSS) Administrative Charge. Details by USoA and charge type can be found in Table 3-9.

Retailer Service Charges – 4082 and Service Transaction Requests - 4084

Whitby Hydro proposes maintenance of the currently approved charges. There are no variances in these accounts beyond volume related changes for customers with a retailer contract. In order to reconcile to historical revenue amounts, adjustments have been made where appropriate to clear entries to RCVA accounts.

SSS Administrative Charge - 4090

Whitby Hydro proposes to continue the Standard Supply Service Administrative Charge of $0.25 per customer per month. The associated revenues have increased from 2006 and are in line with actual and projected customer growth.

Rent from Electric Property - 4210

Rent from Electric Property has fluctuated primarily from changes in Pole Rental Revenue from year to year based on the number of pole attachments. The 2009 forecast includes a one-time catch-up billing adjustment for pole rentals of approximately $12,500. The 2010 revenue levels are comparable to 2009 levels excluding this adjustment.

OTHER INCOME AND EXPENSE

Other Income and Expense includes Revenues and Expenses from Non-Utility Operations, Miscellaneous Non-Operating Income and Interest and Dividend Income. A breakdown has been provided in Table 3-10.

Revenue and Expenses from Non-Utility Operations – 4375 & 4380

The revenue and expenses in these accounts reflect the level of contracted services between Whitby Hydro and the OPA for conservation and demand management. These programs began in 2007 and have increased in 2008 and 2009 as the OPA refined and augmented its program offerings. It is Whitby Hydro's current practice to use all funds available through the OPA to promote and support the programs. As per the Board's CDM guidelines, all of the allowed profits and any liabilities accrue solely to the shareholder. For that reason, the OPA CDM accounts have been excluded from the revenue offsets for rate making purposes.

Miscellaneous Non-Operating Income – 4390

Miscellaneous Non-Operating Income is made up primarily of sales of scrap material and miscellaneous items as well as revenue associated with stale-dated cheques. As a result, this account fluctuates from year to year depending on the volumes associated with these types of activity. In 2009, the revenues associated with stale-dated cheques have been higher than normal due to the downturn in the economy and thus the 2010 levels reflect more typical levels.

Interest and Dividend Income - 4405

Interest income has been separated into three lines in Table 3-10. Regulatory Asset interest/expense; 2) Interest from customer/retailer deposits and PILs interest; and 3) Interest from remaining bank balances. Items 1) & 2) are shown in the table for completeness however, they are not included in the revenue offset. Other interest income declined in 2008 and is expected to do so dramatically in 2009 due to the significant decline in interest rates on deposits. Whitby Hydro has assumed a modest improvement in short-term interest rates in 2010. Whitby Hydro does not receive any dividend income.

1 # APPENDIX 2-D: OTHER OPERATING REVENUE

2 ## Table 3-6: Other Operating Revenue

Uniform System of Account #	Description	2006 Board Approved	2006	2007	2008	Bridge Year 2009	Test Year 2010
4235	Specific Service Charges	196,518	136,946	154,281	249,082	154,835	157,835
4225	Late Payment Charges	275,846	297,895	343,757	321,056	375,000	321,000
4082	Retail Services Revenues	36,142	26,484	49,662	47,569	57,121	57,021
4084	Service Transaction Requests	52	576	555	581	719	719
4090	Electric Services	121,672	129,635	132,026	139,883	141,158	143,048
4210	Rent from Electric Property	105,714	105,855	118,473	124,391	146,093	133,120
4390	Miscellaneous Non-Operating Income	24,933	18,831	46,568	22,827	45,000	25,000
4405	Interest and Dividend Income	620,858	468,611	292,736	7,450	(11,279)	9,407
4375	Revenues from Non-Utility Operations	0	0	273,741	266,394	986,717	986,717
4380	Expense of Non-Utility Operations	0	0	(273,744)	(207,759)	(944,640)	(944,640)
Specific Service Charges 2-D(a)		196,518	136,946	154,281	249,082	154,835	157,835
Late Payment Charges 2-D (b)		275,846	297,895	343,757	321,056	375,000	321,000
Other Distribution Revenues 2-D (c)		263,580	262,550	300,716	312,425	345,091	333,908
Other Income and Expenses 2-D (d)		645,791	487,442	339,301	88,912	75,798	76,484
Total		**1,381,735**	**1,184,832**	**1,138,056**	**971,475**	**950,724**	**889,227**
Adjustments to Revenue Offset:							
4405 Interest from Regulatory Assets		(434,717)	(207,798)	32,754	269,647	61,279	56,593
4405 Interest and Dividend Income - Customer/Retailer Deposit and PILs Interest		(52,297)	(59,477)	(67,863)	(48,081)	(7,000)	(13,000)
4375 Non-Utility Revenue (OPA)		0	0	(273,741)	(266,394)	(986,717)	(986,717)
4380 Non-Utility Expense (OPA)		0	0	273,744	207,759	944,640	944,640
Total Revenue Offset		**894,721**	**917,557**	**1,102,950**	**1,134,406**	**962,926**	**890,743**

Table 3-7: 2-D (a) Specific Service Charge Detail

USoA	Description	2006	2007	2008	Bridge Year 2009	Test Year 2010
4235	Arrears Certificate	0	0	0	0	0
4235	Statement of Account	0	0	0	0	0
4235	Pulling post-dated cheques	0	0	15	0	0
4235	Easement Letter	2,292	2,710	1,317	0	0
4235	Account history	1,521	1,712	1,501	1,500	1,500
4235	Credit reference/credit check (plus credit agency costs)	6,083	6,849	6,004	6,210	6,210
4235	Account set up charge / change of occupancy charge	85,696	122,675	129,690	112,020	115,020
4235	Returned Cheque charge (plus bank charges)	17,120	13,786	14,050	15,000	15,000
4235	Special Meter reads	0	0	0	0	0
4235	Meter dispute charge plus Measurement Canada fees (if meter found correct)	0	0	0	0	0
4235	Collection of account charge – no disconnection	591	0	0	0	0
4235	Collection of account charge – no disconnection – after regular hours	0	0	0	0	0
4235	Disconnect/Reconnect at meter – during regular hours	10,530	14,625	13,390	15,990	15,990
4235	Disconnect/Reconnect at meter – after regular hours	370	925	1,630	740	740
4235	Disconnect/Reconnect at pole – during regular hours	555	1,295	740	1,110	1,110
4235	Disconnect/Reconnect at pole – after regular hours	0	0	415	0	0
4235	Install / remove load control device – during regular hours	0	0	65	65	65
4235	Install / remove load control device – after regular hours	0	0	0	0	0
4235	Service call – customer-owned equipment	0	0	0	0	0
4235	Service call – after regular hours	0	0	0	0	0
4235	Temporary service install and remove – overhead – no transformer	3,000	4,500	4,000	1,500	1,500
4235	Temporary service install and remove – underground – no transformer	9,490	6,000	6,600	1,800	1,800
4235	Temporary service install and remove – overhead – with transformer	650	0	1,000	0	0
4235	Legal letter charge	0	0	0	1,200	1,200
4235	Miscellaneous Revenue	10,416	(10,296)	80,266	1,000	1,000
4235	Temporary Services Expense	(11,368)	(10,500)	(11,600)	(3,300)	(3,300)
Total		**136,946**	**154,281**	**249,083**	**154,835**	**157,835**

Table 3-8: 2-D (b) Late Payment Charge Detail

USoA	Description	2006	2007	2008	Bridge Year 2009	Test Year 2010
4225	Late Payment - per month	297,895	343,757	321,056	375,000	321,000
Total		**297,895**	**343,757**	**321,056**	**375,000**	**321,000**

Table 3-9: 2-D (c) Other Distribution Revenue Detail

USoA	Description	2006	2007	2008	Bridge Year 2009	Test Year 2010
4082	Retailer Service Agreement -- One time charge to establish the service agreement	200	400	0	100	0
4082	Retailer Service Agreement -- monthly fixed charge (per retailer)	2,300	2,840	3,360	3,820	3,820
4082	Retailer Service Agreement -- monthly variable charge (per customer, per retailer)	9,640	29,155	28,346	33,335	33,335
4082	Distributor-Consolidated Billing -- monthly charge (per customer, per retailer)	14,352	17,319	15,935	19,866	19,866
4082	Retailer-Consolidated Billing -- monthly credit (per customer, per retailer)	(8)	(52)	(71)	(0)	(0)
Total	**4082 Retail Service Revenues**	**26,484**	**49,662**	**47,569**	**57,121**	**57,021**
4084	Service Transaction Request -- request fee (per request, applied to the requesting party)	829	1,135	649	526	526
4084	Service Transaction Request -- processing fee (per request, applied to the requesting party)	108	369	182	193	193
4084	Service Transaction Request - request for customer information if not delivered through the EBT system, applied to the requesting party (more than twice per year, per request plus incremental delivery costs)	0	0	0	0	0
	4084 Entry to clear balance to RCVA Variance Account	(360)	(949)	(250)	0	0
Total	**4084 Service Transaction Requests**	**576**	**555**	**581**	**719**	**719**
4090	**Standard Supply Service -- Administrative Charge**	**129,635**	**132,026**	**139,883**	**141,158**	**143,048**
4210	**Rent from Electric Property**	**105,855**	**118,473**	**124,391**	**146,093**	**133,120**
Total		**262,550**	**300,716**	**312,425**	**345,090**	**333,907**

1 **Table 3-10: 2-D (d) Other Income and Expense Detail**

USoA	Description	2006	2007	2008	Bridge Year 2009	Test Year 2010
4375	**Revenues from Non-Utility Operations**	**0**	**273,741**	**266,394**	**986,717**	**986,717**
4380	**Expense of Non-Utility Operations**	**0**	**(273,744)**	**(207,759)**	**(944,640)**	**(944,640)**
4390	**Miscellaneous Non-Operating Income**	**18,831**	**46,568**	**22,827**	**45,000**	**25,000**
4405	Interest and Dividend Income - Bank Interest	201,336	257,627	229,016	43,000	53,000
4405	Interest and Dividend Income - Customer/Retailer Deposits and PILs Interest	59,477	67,863	48,081	7,000	13,000
4405	Interest and Dividend Income - Regulatory Assets	207,798	(32,754)	(269,647)	(61,279)	(56,593)
Total 4405 Interest and Dividend Income		**468,611**	**292,736**	**7,450**	**(11,279)**	**9,407**
Total		**487,442**	**339,301**	**88,912**	**75,798**	**76,484**
Portion to exclude from Revenue Offset:						
4405	Interest and Dividend Income - Regulatory Assets	(207,798)	32,754	269,647	61,279	56,593
4405	Interest and Dividend Income - Customer/Retailer Deposit and PILs Interest	(59,477)	(67,863)	(48,081)	(7,000)	(13,000)
4375	Revenues from Non-Utility Operations	0	(273,741)	(266,394)	(986,717)	(986,717)
4380	Expense of Non-Utility Operations	0	273,744	207,759	944,640	944,640
Revenue Offset - Other Income and Expense		**220,167**	**304,195**	**251,843**	**88,000**	**78,000**

1 **ATTACHMENT 3-1: LOAD FORECAST REPORT**

Weather Normalized Distribution System Load Forecast – 2010 Test Year

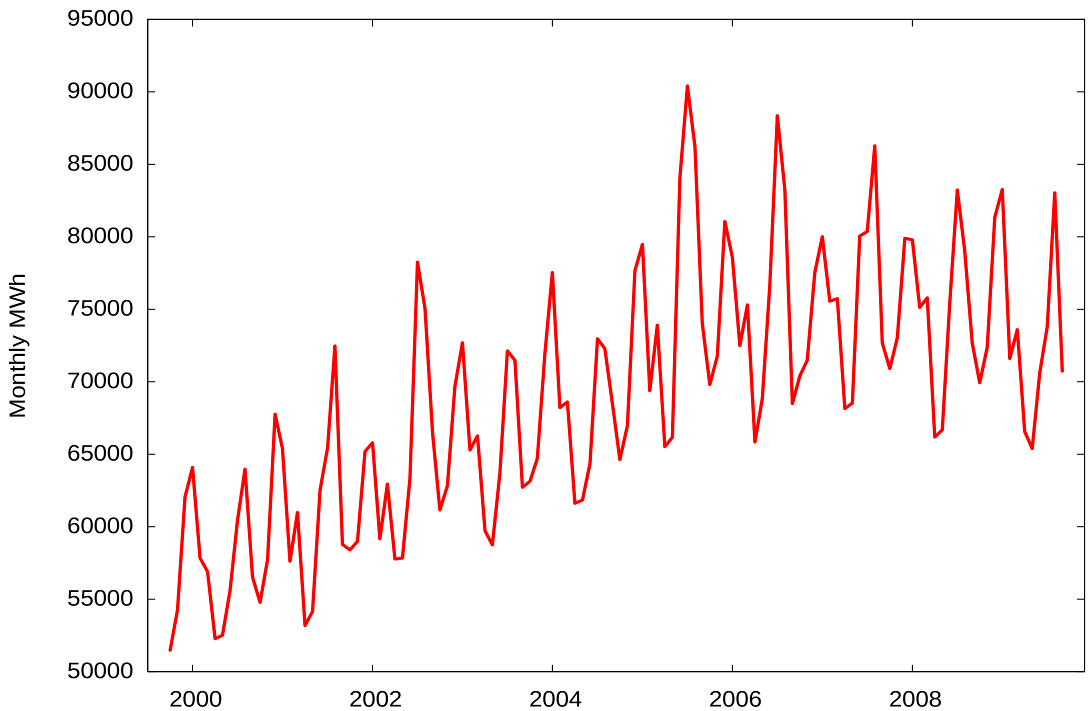
Prepared for Whitby Hydro Electric Corporation

November 3, 2009

1. Introduction

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Whitby Hydro Electric Corporation's rebasing rate application for 2010 rates. A weather normal load forecast is developed for the bridge year (2009) and test year (2010) and weather normalized historical consumption is also derived.

Chart 1: Whitby Hydro Monthly Wholesale Deliveries



The forecast for Whitby Hydro Electric Corporation is based on monthly wholesale deliveries to the Distribution System from October 1999 to September 2009, which encompasses 10 years of wholesale data (120 monthly observations). Forecasting based on class specific data was also investigated; however, data limitations relating to billed versus consumed due to the billing cycle at Whitby Hydro precluded this approach from being used. Chart 1 below illustrates the monthly MWh deliveries. The chart also illustrates the strong consumption growth seen at the beginning of the decade, followed by a more stable, slightly declining trend since 2006 (on a weather actual basis).

2. Energy Forecast Using Wholesale kWh Deliveries

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Whitby, we have used monthly HDD and CDD as reported at Pearson International Airport near Toronto.

Overall economic activity also impacts energy consumption. In order to measure the impact of change in economic activity on energy consumption, a data series must be chosen which represents, as much as possible, regional economic activity. We are unaware of any statistical agency that produces monthly economic accounts on a regional basis. However, regional employment levels are available. Given that income from employment and labour sources accounts for the largest portion of GDP on an income basis, and a recent study by Statistics Canada that has indicated that "turning points in the growth of output and employment appear to have been virtually the same over the past three decades"[1], we have chosen to use employment as the economic variable. We have used the monthly full-time employment levels for the Oshawa Census Metropolitan Area (CMA), as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v3473199). We have also included as an explanatory variable the number of days in the month as well as a dummy variable for off-peak months of April, May, October and November, and a dummy variable to account for lower than expected consumption in some months of 2003.[2]

Using these data, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual energy and the explanatory variables.

The resulting equation, estimated using the 120 observations from 1999:10-2009:09 is displayed in Table 1.

[1] Philip Cross, "Cyclical changes in output and employment," *Canadian Economic Observer*, May 2009.

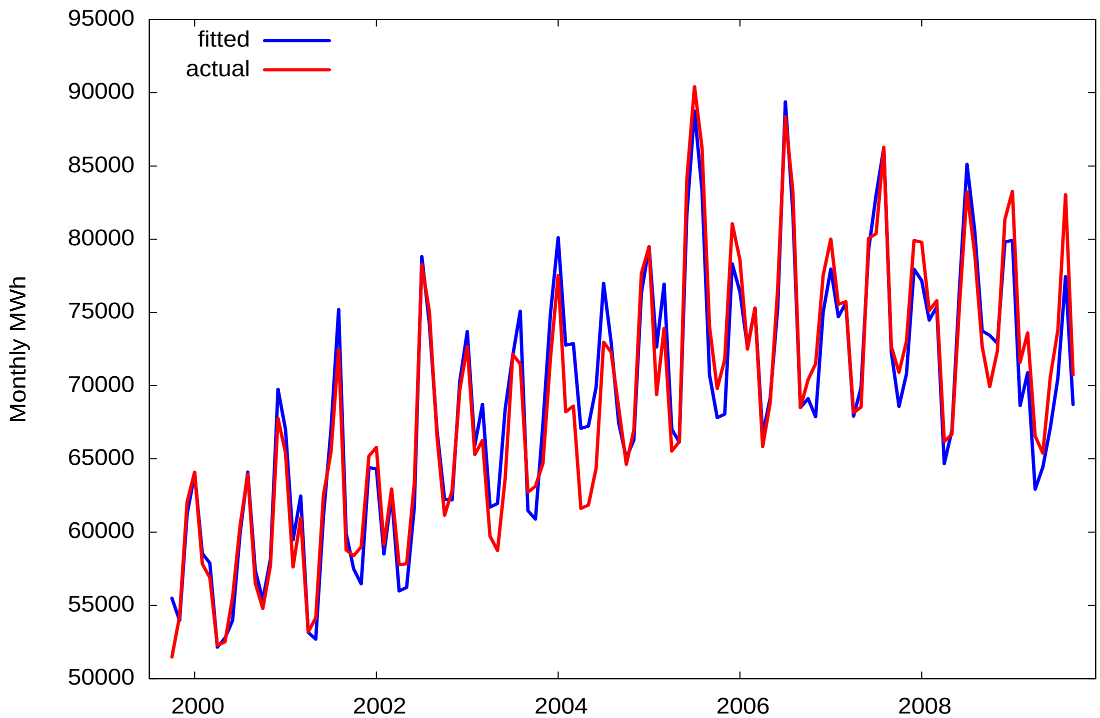
[2] This could be partly due to lingering effects of the blackout as well as other reasons. This has no effect to forecast values but simply helps the model to predict historical values in 2003.

Table 1: OLS, using observations 1999:10-2009:09 (T = 120)
Dependent variable: *WholesalekWh*

variable	coefficient	t-ratio	p-value
const	-70001063.39	-8.30215	2.48E-13
HDD_Tor	19008.23369	14.75147	4.18E-28
CDD_Tor	124184.0362	16.49074	7.45E-32
Monthdays	1603090.995	6.069889	1.75E-08
FTE_Oshawa	587262.2006	29.44907	7.74E-55
DOffPeak	-2403885.946	-4.35462	2.94E-05
D2003	-7568757.16	-6.44472	2.94E-09
R-squared	0.935	*Adj R-squared*	0.932
F(6, 113)	272.75	*P-value(F)*	8.77e-65
Mean Absolute Percent Error (monthly)			2.0527
Theil's U			0.34622

1 Fitted vs. actual observations are plotted in Chart 2 below:

Chart 2: Whitby Hydro Actual vs Fitted Wholesale



Annual estimates using actual weather are compared to actual values in Table 2 below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.3%.

Table 2: Actual Deliveries vs. Estimates, Whitby Hydro

Year	*Actual wholesale kWh*	*Predicted kWh*	*Absolute % Error*
2000	700,365,000	704,021,282	0.5%
2001	733,129,000	736,301,675	0.4%
2002	780,336,017	773,952,451	0.8%
2003	792,491,625	812,227,996	2.5%
2004	825,196,089	855,034,407	3.6%
2005	911,868,734	900,850,904	1.2%
2006	897,193,025	887,026,073	1.1%
2007	911,211,760	904,260,661	0.8%
2008	897,673,634	900,858,274	0.4%
		Mean Absolute Percentage Error (annual)	***1.3%***

1.1 Weather Normalization and Forecasted kWh

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. The OEB has considered and approved several different approaches to what constitutes “weather normal” over the past several years. For gas utilities, the Board has approved a five-year moving average for NRG (RP-2004-0167), a weighted average of 20 year and 30 year for Union Gas (RP-2003-0063), and a combination of methods including a 20 year trend, weighted average 20 year and 30 year, and variations of the so-called “de Bever” method depending upon location for Enbridge Gas Distribution (EB-2006-0034). For electric LDCs, Hydro One Networks Inc. (HONI) has used a 31 year average for their definition of weather normal (EB-2005-0378 and EB-2007-0681). On the other hand, Toronto Hydro Electric System Limited (THESL) has used the most recent 10 year average as a definition of weather normal (EB-2005-0421 and EB-2007-0680) as have many of the LDCs that filed for cost-of-service rebasing for 2009 rates. Whitby has adopted the 10 year average from 1999 to 2008 as the definition of weather normal. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the “average” weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing.

In Table 3 below, we outline the 10-year monthly HDD and CDD for Pearson International Airport, the weather station selected for Whitby Hydro.

Table 3: HDD and CDD - Pearson Int'l Airport, Jan 1999 to Dec 2008

Heating Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	749.8	548.1	550.6	296.7	97.1	25.0	0.0	8.4	49.3	267.6	367.5	579.3	3539.4
2000	738.9	612.7	418.6	339.2	139.6	34.5	6.6	11.5	99.5	212.7	432.0	780.3	3,826.1
2001	684.9	587.6	566.6	293.8	111.5	29.8	9.3	0.0	73.6	232.5	325.8	505.0	3,420.4
2002	572.2	540.2	545.6	329.5	227.5	36.2	0.0	0.2	21.8	292.2	445.0	619.4	3,629.8
2003	814.5	699.0	581.1	372.5	177.9	43.4	0.2	2.0	54.9	276.0	398.5	561.5	3,981.5
2004	849.1	631.7	487.3	331.5	158.9	44.2	3.6	12.8	30.0	226.3	379.1	643.4	3,797.9
2005	770.0	616.4	608.6	306.8	189.4	8.9	0.0	0.2	22.6	220.2	388.4	665.3	3,796.8
2006	551.8	604.3	516.6	293.3	136.9	19.5	0.0	4.2	80.9	288.3	382.2	500.5	3,378.5
2007	647.1	740.1	546.7	356.4	136.4	16.5	3.2	5.2	36.9	137.7	462.5	630.7	3,719.4
2008	623.5	674.7	610.2	253.9	193.5	22.7	1.0	12.7	59.0	278.6	451.6	654.6	3,836.0
10-yr avg	***700.2***	***625.5***	***543.2***	***317.4***	***156.9***	***28.1***	***2.4***	***5.7***	***52.9***	***243.2***	***403.3***	***614.0***	***3692.6***

Cooling Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	0.0	0.0	0.0	0.0	19.4	96.0	196.5	79.1	48.9	0.0	0.0	0.0	439.9
2000	0.0	0.0	0.0	0.0	23.7	41.1	71.8	92.5	35.2	1.2	0.0	0.0	265.5
2001	0.0	0.0	0.0	1.4	12.2	79.7	100.9	160.0	35.7	2.0	0.0	0.0	391.9
2002	0.0	0.0	0.0	8.3	7.8	70.0	192.4	142.7	87.6	10.0	0.0	0.0	518.8
2003	0.0	0.0	0.0	2.4	0.0	52.9	118.3	128.0	24.0	0.0	0.0	0.0	325.6
2004	0.0	0.0	0.0	0.0	8.6	31.6	86.4	59.6	41.2	1.5	0.0	0.0	228.9
2005	0.0	0.0	0.0	0.0	0.8	146.3	188.7	140.7	52.1	7.6	0.0	0.0	536.2
2006	0.0	0.0	0.0	0.0	26.0	73.6	167.3	101.6	12.9	1.1	0.0	0.0	382.5
2007	0.0	0.0	0.0	0.0	22.4	99.2	106.1	141.0	47.5	19.8	0.0	0.0	436
2008	0.0	0.0	0.0	0.0	2.5	71.5	111.0	64.0	26.7	0.0	0.0	0.0	275.7
10-yr avg	***0.0***	***0.0***	***0.0***	***1.2***	***12.3***	***76.2***	***133.9***	***110.9***	***41.2***	***4.3***	***0.0***	***0.0***	***380.1***

Forecasts for Ontario's employment outlook for 2009 and 2010 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 4: Employment Forecast – Ontario
(figures in annual percentage change)

	BMO	RBC	Scotia	TD	Avg
	(Oct 16,2009)	*(Sep 2009)*	*(July 30, 2009)*	*(July 16 ,2009)*	
2009	-2.4	-2.4	-2.8	-2.7	-2.6
2010	1.0	1.0	0.5	-0.5	0.5

Incorporating the forecast economic variables, 10-yr weather normal heating and cooling degree days, and the other explanatory variables, the following weather corrected consumption and forecast values are calculated:

Table 5: Weather Corrected Wholesale kWh, Whitby Hydro				
			10-yr (1999-2008)	
Year	Actual wholesale kWh	%chg	Weather Normal	%chg
2002	780,336,017	*6.4%*	757,921,462	*2.4%*
2003	792,491,625	*1.6%*	813,504,167	*7.3%*
2004	825,196,089	*4.1%*	871,809,086	*7.2%*
2005	911,868,734	*10.5%*	879,484,737	*0.9%*
2006	897,193,025	*-1.6%*	892,698,137	*1.5%*
2007	911,211,760	*1.6%*	896,808,972	*0.5%*
2008	897,673,634	*-1.5%*	911,096,927	*1.6%*
2009			882,068,691	*-3.2%*
2010			886,766,789	*0.5%*

3 Class Specific Weather Normalization and Consumption Forecasts

In Table 6 below, we present annual (weather actual) class data which has been adjusted for unbilled amounts (e.g., amounts billed for previous year consumption or unbilled current year consumption). The table also shows the share of class consumption in wholesale (exclusive of distribution losses).

Table 6: Annual Historic Weather-Actual Class kWh Throughput, Whitby Hydro

	Wholesale Purchases	Residential	*share*	GS<50	*share*	GS>50	*share*
2004	825,196,089	311,621,606	*0.3776*	69,602,804	*0.0843*	404,448,037	*0.4901*
2005	911,868,734	347,694,940	*0.3813*	73,582,378	*0.0807*	435,533,612	*0.4776*
2006	897,193,025	340,108,142	*0.3791*	72,200,337	*0.0805*	433,954,842	*0.4837*
2007	911,211,760	353,245,947	*0.3877*	74,193,328	*0.0814*	433,427,583	*0.4757*
2008	897,673,634	342,735,162	*0.3818*	76,238,506	*0.0849*	428,355,126	*0.4772*
Jan-Sep 2009	658,586,802	260,241,528	*0.3952*	55,812,974	*0.0847*	307,877,609	*0.4675*

	Streetlights	*share*	Sentinel Lights	*share*	USL	*share*
2004	8,171,312	*0.0099*	63,396	*0.0001*	2,569,913	*0.0031*
2005	8,309,471	*0.0091*	62,860	*0.0001*	2,736,453	*0.0030*
2006	8,538,442	*0.0095*	59,876	*0.0001*	2,513,103	*0.0028*
2007	8,671,157	*0.0095*	54,867	*0.0001*	2,478,838	*0.0027*
2008	8,809,935	*0.0098*	53,420	*0.0001*	2,470,423	*0.0028*
Jan-Sep 2009	6,224,807	*0.0095*	36,035	*0.0001*	1,843,695	*0.0028*

For the weather sensitive consumption classes (residential, GS<50, GS>50), historic weather normal class specific kWh consumption is allocated based on each class' historic share in wholesale kWh (both weather actual), exclusive of distribution losses. Forecast class values are allocated based on the class share for 2009 year-to-date. Forecast class kWh for classes that are not weather sensitive (street light, sentinel light, USL) are based on use per customer for the most recent historical year (2008). Table 7 below summarizes the weather normal forecast by class.

Table 7: 10-yr (1999-2008) Weather Normal kWh Throughput, Whitby Hydro

	Wholesale kWh	Residential	% chg	GS < 50	% chg	GS>50	% chg
2004	871,809,086	329,224,230		73,534,470		427,294,165	
2005	879,484,737	335,346,944	1.9%	70,969,182	-3.5%	420,066,123	-1.7%
2006	892,698,137	338,404,218	0.9%	71,838,617	1.2%	431,780,752	2.8%
2007	896,808,972	347,662,474	2.7%	73,020,614	1.6%	426,576,744	-1.2%
2008	911,096,927	347,860,226	0.1%	77,378,533	6.0%	434,760,501	1.9%
2009F	882,068,691	348,550,720	0.2%	74,752,298	-3.4%	412,351,415	-5.2%
2010F	886,766,789	350,407,180	0.5%	75,150,446	0.5%	414,547,692	0.5%

	Street Light	% chg	Sentinel Light	% chg	USL	% chg
2004	8,171,312		63,396		2,569,913	
2005	8,309,471	1.7%	62,860	-0.8%	2,736,453	6.5%
2006	8,538,442	2.8%	59,876	-4.7%	2,513,103	-8.2%
2007	8,671,157	1.6%	54,867	-8.4%	2,478,838	-1.4%
2008	8,809,935	1.6%	53,420	-2.6%	2,470,423	-0.3%
2009F	8,931,971	1.4%	48,635	-9.0%	2,487,431	0.7%
2010F	9,090,771	1.8%	43,361	-10.8%	2,493,809	0.3%

Class kW

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 8 below. Historical normalized values are calculated based on the annual ratio of class kW to class kWh. Forecast kW is based on the class kW to class kWh ratio in 2008.

Table 8: GS>50 Class kW (Actual, Normalized, and Forecast)

Year	**Actual kW**	**Class kW/kWh ratio**	**Normalized kW**	**% change**
2004	905,520	0.002239	956,670	1.8%
2005	1,000,149	0.002296	964,630	0.8%
2006	996,785	0.002297	991,791	2.8%
2007	997,932	0.002302	982,158	-1.0%
2008	998,516	0.002331	1,013,447	3.2%
2009F			961,211	-5.2%
2010F			966,330	0.5%

Forecast kW for street lighting and sentinel lighting is based on the annual kW to kWh ratio for 2008 and the forecast kWh for 2009 and 2010 based on use per customer, as these classes' consumption is not weather sensitive.

A summary of the forecast for the historic (2008), bridge (2009) and test (2010) years is displayed in Table 9 below.

Table 9: Load Forecast Summary (Historical, Bridge and Test Years).

	2008 Actual	2008 Normalized	2009f Normalized	2010f Normalized
Residential (kWh)	342,735,162	347,860,226	348,550,720	350,407,180
GS<50 (kWh)	76,238,506	77,378,533	74,752,298	75,150,446
GS>50 (kWh)	428,355,126	434,760,501	412,351,415	414,547,692
(kW)	998,516	1,013,447	961,211	966,330
Street Lights (kWh)	8,809,935	8,809,935	8,931,971	9,090,771
(kW)	23,609	23,609	23,936	24,361
Sentinel Lights (kWh)	53,420	53,420	48,635	43,361
(kW)	148	148	135	120
USL (kWh)	2,470,423	2,470,423	2,487,431	2,493,809
Total Retail kWh	858,662,572	871,333,037	847,122,470	851,733,259

4. Customer Forecast

The following table (Table 10) develops the customer forecast for Whitby Hydro for 2009 and 2010 as well as displaying the historical average annual customer counts, by class, since 2002.

Table 10

Whitby Hydro Customers by Class

Year	Res	GS<50	GS>50	Street	Sent	USL
2002	27,922	1,659	344	9,145	53	378
2003	29,682	1,670	361	9,750	53	381
2004	31,861	1,735	377	10,165	53	390
2005	33,225	1,772	393	10,411	53	402
2006	34,506	1,816	405	10,740	50	390
2007	35,300	1,869	412	11,012	47	382
2008	36,030	1,896	423	11,123	46	387
2008 Dec	36,496	1,908	431	11,181	46	390
2009 June	36,575	1,905	431	11,256	35	389
2009 Adds	***238***	***1***	***2***	***193***	***-9***	***0***
2009 YE	36,734	1,909	433	11,374	37	390
2009 Avg	**36,615**	**1,909**	**432**	**11,278**	**42**	**390**
2010 Adds	385	0	3	207	0	1
2010 YE	37,119	1,909	436	11,581	37	391
2010 Avg	**36,927**	**1,909**	**435**	**11,478**	**37**	**391**

The 2008 December Sentinel Light customer connection count is based on the 2008 annual average.

The 2009 and 2010 customer counts are based on Whitby Hydro's assessment of 2009 customer growth, year-to-date, and expected customer attachments for 2010. This, in turn, is based on expectations relating to new subdivision development, the economic outlook for the area (including future prospects for General Motors), and developments in specific classes, such as sentinel lights, unmetered scattered load, and street lights. The underlying assumptions for these expectations are developed in more detail in the pre-filed evidence accompanying the Whitby Hydro Application. We note that the expectations for new residential attachments are consistent with the latest housing market outlook from CMHC.[3]

5. Average Use

Actual use per customer and normalized use per customer resulting from the load forecast are displayed below.

Table 11

Actual Use Per Customer

	Residential	GS<50	GS>50	Streetlights	Sentinel Lights	USL
2004	9,781	40,128	1,072,806	804	1,196	6,595
2005	10,465	41,523	1,107,993	798	1,195	6,813
2006	9,856	39,760	1,071,053	795	1,190	6,440
2007	10,007	39,700	1,051,158	787	1,176	6,492
2008	9,513	40,214	1,013,458	792	1,172	6,378

Normalized Use Per Customer

	Residential	GS<50	GS>50	Streetlights	Sentinel Lights	USL
2004	10,333	42,395	1,133,406	804	1,196	6,595
2005	10,093	40,048	1,068,644	798	1,195	6,813
2006	9,807	39,561	1,065,687	795	1,190	6,440
2007	9,849	39,073	1,034,543	787	1,176	6,492
2008	9,655	40,815	1,028,613	792	1,172	6,378
2009	9,519	39,168	954,517	792	1,172	6,378
2010	9,489	39,366	952,983	792	1,172	6,378

[3] For example, see CMHC Housing Market Outlook – Greater Toronto Area, Fall 2009, p.8.

EXHIBIT 4
OPERATING COSTS

MANAGER'S SUMMARY – OPERATING, MAINTENANCE AND ADMINISTRATION

SCOPE

Whitby Hydro's Operation, Maintenance and Administration (OM&A) expenditures are incurred in order to operate its distribution system efficiently and effectively and to provide quality distribution services to a growing customer base in a safe and reliable manner. OM&A costs are also incurred by Whitby Hydro to ensure compliance with its regulatory environment and government obligations; to meet its operational performance targets and to maintain conditions of service that are congruent with the OEB's hierarchy of distribution, retail and settlement codes. Whitby Hydro has been able to provide customer value by meeting all of these requirements while managing costs to increases of 3.63% per annum since 2004. As discussed below, the OM&A increases during this period were driven mainly by customer growth, labour costs and inflation.

BUDGET PROCESS

Whitby's OM&A planning and cost containment is assisted by its annual budgeting process. A three year operating budget is prepared by Management and approved by Whitby Hydro's Board before the start of each fiscal year. This same three year operating budget is reviewed again in the following June and December and subsequently it is presented to Whitby Hydro's Board for approval.

Each Department Head is responsible for budgeting in their designated area based on the Board's Uniform System of Accounts ("USoA"). The President and Vice President review and approve each Department Head's budget and submit the approved amounts to the Treasurer for compilation into a total budget. The consolidated budget is then reviewed by the President, Vice President and the Treasurer to ensure an appropriate annual spending level.

In recording its costs, Whitby Hydro follows the OEB's Accounting Procedures Handbook in classifying OM&A expenses. Costs associated with non-utility activities are excluded from the utility spending in the OM&A forecast.

OVERVIEW

As noted above, Whitby Hydro's OM&A costs have increased by 3.63% per annum. The increased spending was required to meet the demands of high customer growth while maintaining a safe and reliable system within an increasingly complicated regulatory environment. Whitby Hydro has experienced extreme demand growth increasing its customer base by 49.7% over the past 9 years (1999-2008). As shown in Table 4-2, customer growth over the rebasing period (2004-2010) continues at a more moderate rate of 13.4%; it appears to be easing off in

2007 and 2008 and is forecast to be less than 1.0% in 2009 and 2010 due to economic conditions. The customer growth rate from 1999-2010 is currently projected to increase by 52.1%.

Significant expansion of the distribution system has been necessary in order to service customers. The following statistics provide support to the high level of distribution infrastructure installed:

Infrastructure	% Change
Municipal Substation Transformers (2002-2009)	125.0%
Total kilometers of line (2002-2008)	14.6%
Transformers (2002-2008)	14.8%

It is important to understand the customer growth pattern in conjunction with the related capital spending when analyzing OM&A costs which are not necessarily incurred uniformly with customer growth rates. Cost stability in all areas of the OM&A budget is difficult to maintain when growth has been so significant and it requires swings in allocated resources between operating and capital budgets.

A summary of Whitby Hydro's operating costs for the 2006 Board Approved, 2006 through 2008 Actual, 2009 Bridge Year and the 2010 Test Year are provided in Table 4-1. Whitby Hydro's OM&A costs have increased by $1,719K or 23.87% (3.63% compounded per annum) over the six year period from the 2006 Board Approved (2004 Actual) to the 2010 Forecast. The increase when broken down by component can be described as follows: Operations 6.36%, Maintenance 10.46%, Billing & Collections 5.74% and Administration & General 1.31%.

Table 4-1: Summary of Operating Costs (Appendix 2-F)

Appendix 2-F
Summary of OM&A Expenses ($000)

	2006 Board Approved	2006 Actual	Variance-Board Approved to Actual	2007 Actual	Variance-2007 Actual to 2006 Actual	2008 Actual	Variance-2008 Actual to 2007 Actual	2009 Bridge	Variance-2009 Bridge to 2008 Actual	2010 Test	Variance-2010 Test to 2009 Bridge	Variance-2010 Test to 2006 Board Approved	% Variance-2010 Actual to 2006 Board Approved
Operation	1,513	1,786	273	1,984	198	1,832	(152)	1,866	34	1,971	105	**458**	**6.36%**
Maintenance	1,136	1,678	542	1,907	229	1,635	(272)	1,870	235	1,890	20	**754**	**10.47%**
Billing and Collections	1,753	2,263	510	2,300	37	2,168	(132)	2,041	(127)	2,166	125	**413**	**5.74%**
Administrative and General	2,799	2,433	(366)	2,536	103	2,513	(23)	2,709	196	2,893	184	**94**	**1.31%**
Total OM&A	7,201	8,160	959	8,727	567	8,148	(579)	8,486	338	8,920	434	**1,719**	**23.87%**
Variance from Previous Year		959		567		(579)		338		434			
% Change -Year over Year		13.32%		6.95%		-6.63%		4.15%		5.11%			
% Change Test Year to Most Current Actual (2010 vs. 2008)										9.47%			
% Change 2010 Test Year to 2006 Board Approved										23.87%			
Average for 2007, 2008 & 2009				1.49%									
Compound Annual Growth Rate for 2006 Board Approved to 2010 Test Year										3.63%			

A Cost Trending Analysis (see table below) has been developed to use as a proxy to support costs trends and percentage increases. When the customer growth rates are combined with the industry inflation rate, OM&A costs for the period 2004 through 2010 should have increased by 24.89 per cent, which is in line with the forecast cost increases of 23.87%. Please note, that since an industry price inflator was not available for 2009 and 2010 the 12 month change in CPI was used for November 2009.

Table 4-2: Cost Trending Analysis

Cost Trending Analysis

	2004 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Customer Growth	35,146	37,649	38,279	39,226	39,467	39,856
% Change		7.12	1.67	2.47	0.61	0.99
% Change-ytd		7.12	8.91	11.61	12.29	13.40
IPI*	103.3	107.9	110.3	112.9	114.0	115.2
% Change		4.45	2.22	2.36	1.00	1.00
% Change-ytd		4.45	6.78	9.29	10.39	11.49
Total sum of Customer Growth and IPI Change -%						24.89

*IPI (Implicit chain price indexes-Statistics Canada)
** 2009 and 2010 are based on the November 2009 change in C.P.I.

1 **Table 4-3: Detailed OM&A Expenses by Account (Appendix 2-G)**

Appendix 2-G
Detailed, Account by Account, OM&A Expense Table

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Operations						
5005-Operation Supervision and Engineering	91,670	125,200	126,778	87,155	85,129	93,099
5010-Load Dispatching	333,129	323,535	387,010	282,424	322,791	350,806
5012-Station Buildings and Fixtures Expense	99,370	113,139	130,233	120,097	124,860	129,033
5017-Distribution Station Equipment	12,299	13,248	19,097	34,376	22,249	41,533
5025-Overhead Distribution Lines & Feeders	10,156	31,406	22,217	31,648	31,742	48,705
5030-Overhead Subtransmission Feeders	5,612	5,264	4,807	21,456	21,389	29,881
5035-Overhead Distribution Transformers	8,050	11,296	10,199	8,436	14,345	23,939
5045-Underground Distribution Lines & Feeders	135,651	154,872	184,088	188,976	220,948	240,400
5055-Underground Distribution Transformers	7,556	16,483	11,830	9,896	12,746	29,701
5065-Meter Expense	432,384	496,427	550,000	537,465	400,122	369,727
5075-Customer Premises	65,912	53,139	61,483	77,725	140,288	142,492
5085-Miscellaneous Distribution Expense	302,042	431,557	475,543	417,675	468,001	470,285
5090-Underground Dist. Lines and Feeders - Rental Paid	1,854	0	0	0	0	0
5095-Overhead Dist. Lines and Feeders - Rental Paid	7,390	10,459	543	14,902	1,120	1,120
	1,513,075	1,786,025	1,983,828	1,832,231	1,865,730	1,970,721
Maintenance						
5105-Maintenance Supervision and Engineering	88,221	171,479	179,112	134,535	133,176	155,860
5110-Maintenance of Buildings and Fixtures - Dist. Stations	5,230	2,539	2,720	8,092	5,820	5,815
5114-Maintenance of Distribution Station Equipment	275,086	397,036	508,360	306,851	303,762	316,127
5120-Maintenance of Poles, Towers and Fixtures	18,486	61,438	75,648	62,055	65,259	75,903
5125-Maintenance of Overhead Conductors/Devices	183,385	283,229	242,426	303,023	349,363	310,822
5130-Maintenance of Overhead Services	63,247	65,931	62,261	73,724	111,369	122,149
5135-Overhead Dist. Lines and Feeders - Right of Way	50,120	101,083	87,615	109,546	127,005	131,392
5150-Maintenance of Underground Conductors/Devices	167,626	201,308	295,227	175,145	260,128	213,900
5155-Maintenance of Underground Services	141,448	177,875	233,802	276,260	262,258	280,646
5160-Maintenance of Line Transformers	135,289	195,960	197,518	156,046	197,085	219,350
5175-Maintenance of Meters	7,910	20,455	22,529	30,080	54,734	58,030
	1,136,048	1,678,333	1,907,218	1,635,357	1,869,959	1,889,994
Billing and Collections						
5305-Supervision	27,283	45,726	30,503	45,078	34,003	35,063
5310-Meter Reading Expense	184,831	243,682	196,987	264,107	253,541	258,184
5315-Customer Billing	793,344	535,334	559,722	593,483	603,108	680,570
5320-Collecting	113,798	133,337	131,478	143,910	140,488	143,336
5325-Collecting- Cash Over and Short	0	0	0	0	0	0
5330-Collection Charges	10,163	12,613	19,680	20,034	18,135	20,359
5335-Bad Debt Expense	57,589	135,171	113,528	304,939	200,000	200,000
5340-Miscellaneous Customer Accounts Expenses	562,784	686,886	697,626	792,092	785,283	814,854
5415-Energy Conservation	0	466,290	547,418	0	0	0
5425-Misc. Customer Service and Informational Expenses	3,448	4,405	3,306	4,643	6,801	13,572
	1,753,240	2,263,444	2,300,248	2,168,286	2,041,359	2,165,938
Administrative and General						
5605-Executive Salaries and Expenses	71,455	95,253	128,465	120,964	79,450	60,170
5610-Management Salaries and Expenses	734,848	722,628	667,115	793,372	859,268	913,739
5615-General Administrative Salaries and Expenses	271,841	342,789	418,163	379,086	411,278	479,310
5620-Office Supplies and Expenses	130,753	125,422	135,151	99,150	106,400	109,760
5630-Outside Services Employed	74,948	165,635	127,694	197,068	214,400	238,880
5635-Property Insurance	11,491	30,360	30,360	33,188	36,000	37,000
5640-Injuries and Damages	149,839	71,905	84,217	85,655	85,000	88,000
5645-Employee Pensions and Benefits	183,391	0	0	0	0	0
5655-Regulatory Expenses	129,358	271,883	257,611	288,947	354,108	392,429
5660-General Advertising Expenses	0	5,842	1,712	1,554	2,240	2,240
5665-Miscellaneous General Expenses	727,282	398,913	420,474	330,757	296,600	300,240
5675-Maintenance of General Plant	313,686	202,706	265,306	183,457	224,000	231,000
5685-IESO Fees and penalities					40,000	40,000
	2,798,892	2,433,336	2,536,268	2,513,198	2,708,744	2,892,768
Total Operations, Maintenance and Administration	**7,201,255**	**8,161,138**	**8,727,562**	**8,149,072**	**8,485,792**	**8,919,421**

OM&A COST DRIVERS

An analysis of cost drivers, Table 4-3 (Appendix 2-H) has been provided in the form of a continuity schedule for total OM&A costs and each component group (i.e. Operations, Maintenance, Billing & Collections and Administration). Cost drivers have been grouped where appropriate. The total impact of these drivers over the 6 years (2004 to 2010) is summed under the "Total" column and the change in costs from the 2006 Board Approved (2004 Actual) to the 2010 Test Year is provided.

Total OM&A costs have increased by 23.87% from the 2006 Board Approved to the 2010 Test Year which is predominately due to inflation which totaled 17.3% over the period. Growth related costs at 9.9% (mainly labour) are additional resources required to support significant system expansion and service higher customer levels. Increased compliance requirements contribute 2% as do escalating bad debt levels.

Table 4-4: OM&A Cost Driver Table (Appendix 2-H) - $000's

Appendix 2-H
OM&A Cost Driver Table

USoA	Description	Note	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Bridge	2006 Board Approved to 2010 Test Year	
								Total Change $	Total Change %
	Opening Balance	1	**7,201**	**8,160**	**8,727**	**8,148**	**8,486**	**7,201**	
	Inflationary increases		324	239	228	226	233	1,250	17.4%
	Growth Related Costs								
5085,5045	Additional Operations		128	58	(68)	67	6	191	
5114-5160	Additional Maintenance		352	197	(296)	163	(45)	371	
5340	Additional Customer Service		97	(9)	75	(26)	11	148	
			577	246	(289)	204	(28)	710	9.9%
	Increased Compliance Requirements								
5655	Regulatory acitivty-OEB related		21	(14)	31	65	38	141	2.0%
5335	Bad Debt Expense		78	(22)	191	(105)	0	142	2.0%
5415	CDM		466	81	(547)			0	0.0%
5665	Low Voltage-reclassified as regulatory asset for 2006 actuals as per OEB direction		(457)					(457)	-6.3%
	Other		(50)	37	(193)	(52)	191	(67)	-0.9%
	Ending balance		**8,160**	**8,727**	**8,148**	**8,486**	**8,920**	**8,920**	**23.87%**

Notes:
1. Opening balance for 2006 Actual is the 2006 Board Approved amount.

The variance threshold used to identify the OM&A accounts requiring explanation has been prescribed by the Filing Requirements as 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million. Accordingly, Whitby Hydro has based the threshold on the proposed revenue requirement of $20,747,189 and adopted a variance threshold of $103,736 throughout this analysis.

Operations

Operation costs have increased by 30.3% from the 2006 Board Approved amount. The increase is largely due to Inflation which explains 18.5%, combined with growth related costs for increased engineering staff and an increased demand for underground cable locating of 12.6%. As Whitby Hydro's underground plant has grown significantly, so has the requirement for underground locating combined with the additional regulatory pressure for third party contractors to remain compliant.

A cost driver continuity has been provided in Table 4-5 to summarize the change from 2006 Board Approved to 2010 test year.

Table 4-5: Operations Cost Driver Table ($000's)

Appendix 2-H

Operations Cost driver Table

Description/USoA	Note	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2006 Board Approved to 2010 Test Year Total Change $	2006 Board Approved to 2010 Test Year Total Change %
Opening Balance	1	1,513	1,786	1,984	1,832	1,866	1,513	
Inflation on 2006 Approved costs		73	54	51	51	52	280	18.5%
Additional resources due to growth related								
5085-Miscellaneous Distribution Expense		**130**	44	(58)	50	2	168	
5045-Underground Distribution Lines & Feeders		19	29	5	32	19	104	
Inflation	2	(21)	(15)	(15)	(15)	(15)	(81)	
	3	128	58	(68)	67	6	191	12.6%
5010-Load Dispatching		(10)	63	**(105)**	40	28	16	1.1%
5065-Meter Expense		64	54	(13)	**(137)**	(30)	(62)	-4.1%
Other		18	(31)	(17)	13	49	33	2.2%
		1,786	1,984	1,832	1,866	1,971	1,971	30.3%

Notes:
1. Opening balance for 2006 Actual is the 2006 Board Approved amount.
2. In order to maintain the information at USoA level, variances are reported on a gross basis including inflationary impacts associated with 2006 Approved cost levels. This inflation component has been calculated and removed at the USoA level to avoid duplication with costs which are already included in the inflation line above.
3. USoA costs excluding inflation associated with 2006 approved levels.

The following accounts which exceed the materiality threshold and have been identified in the continuity (Table 4-5) are also explained in detail below.

USoA	2006 Actual-2006 Board Approved	2007 Actual-2006 Actual	2008 Actual-2007 Actual	2009 Bridge - 2008 Actual	2010 Test-2009 Bridge
Operations					
5010-Load Dispatching			(104,586)		
5065-Meter Expense				(137,343)	
5085-Miscellaneous Distribution Expense	129,515				

2006 Actual versus 2006 Board Approved

USoA		2006 Actual	2006 Board Approved	Variance
5085	Miscellaneous Distribution Expense	431,557	302,042	129,515

Additional Engineering resources were acquired in 2005-2006 to provide the design component for the continued system expansion that was required to support customer growth.

2008 Actual versus 2007 Actual

USoA		2008 Actual	2007 Actual	Variance
5010	Load Dispatching	282,424	387,010	(104,586)

Copper cable thefts were a major occurrence in 2007 through the GTA and were a recurring problem for Whitby Hydro. The re-configuration of substation grounding conductor work in 2008 acted as a deterrent for further theft which resulted in reduced control room costs in 2008.

2009 Bridge Year versus 2008 Actual

USoA		2009 Bridge Year	2008 Actual	Variance
5065	Meter Expense	400,122	537,465	(137,343)

Labour resources were deployed to the Smart Meter Program in 2009, specifically to work with meters which are located inside the customer's premise. These costs have been charged to the Smart Meter variance account. Once Whitby Hydro's Smart Meter project has been completed, these staff will be installing meters through the regular annual program for new meters.

Maintenance

Maintenance costs have increased by 66.4% from the 2006 Board Approved amount. Inflation contributed to this change; however, a significant portion of the increase is due to additional resources acquired in 2005-2006 that were necessary to maintain the rapidly expanding distribution system and support significant customer growth. Copper thefts were a major occurrence for Whitby in 2007 which caused costs to rise, however these thefts and associated costs were significantly reduced for 2008. In addition, during 2008 material and labour costs associated with major repairs and betterments previously classified as maintenance were properly capitalized.

In 2009, work forces shifted more time from capital work to address specific overhead and underground system maintenance requirements. This pattern continues in the test year however, 2010 costs have been normalized to take into account the fact that maintenance is expected to return to more typical levels in 2011-2013.

Table 4-6: Maintenance Cost Drivers ($000's)

Appendix 2-H
Maintenance Cost driver Table

							2006 Board Approved to 2010 Test Year	
Description/USoA	Note	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test	Total Change $	Total Change %
Opening Balance	1	1,136	1,678	1,907	1,635	1,870	1,136	
Inflation on 2006 Approved costs		55	40	38	38	39	211	18.5%
Additional resources due to growth related								
5114-Maintenance of Distribution Station Equipment		122	111	(202)	(3)	12	40	
5120-Maintenance of Poles, Towers and Fixtures		43	14	(14)	3	11	57	
5125-Maintenance of Overhead Conductors/Devices		100	(41)	61	46	(39)	127	
5130-Maintenance of Overhead Services		3	(4)	11	38	11	59	
5150-Maintenance of Underground Conductors/Devices		34	94	(120)	85	(46)	47	
5155-Maintenance of Underground Services		36	56	42	(14)	18	138	
5160-Maintenance of Line Transformers		61	2	(41)	41	22	85	
Inflation	2	(47)	(35)	(33)	(33)	(34)	(182)	
	3	352	197	(296)	163	(45)	371	32.7%
5135-Overhead Dist. Lines and Feeders - Right of Way		51	(13)	22	17	4	81	7.1%
Other		84	5	(36)	17	22	91	8.1%
		1,678	1,907	1,635	1,870	1,890	1,890	66.4%

Notes:
1. Opening balance for 2006 Actual is the 2006 Board Approved amount.
2. In order to maintain the information at USoA level, variances are reported on a gross basis including inflationary impacts associated with 2006 Approved cost levels. This inflation component has been calculated and removed at the USoA level to avoid duplication with costs which are already included in the inflation line above.
3. USoA costs excluding inflation associated with 2006 approved levels.

The following accounts which exceed the materiality threshold and have been identified in the continuity (Table 4-6) are also explained in detail below.

USoA	2006 Actual-2006 Board Approved	2007 Actual-2006 Actual	2008 Actual-2007 Actual	2009 Bridge - 2008 Actual	2010 Test-2009 Bridge
Maintenance					
5114-Maintenance of Distribution Station Equipment	121,950	111,324	(201,509)		
5150-Maintenance of Underground Conductors and Devices			(120,082)		

2006 Actual versus 2006 Board Approved

USoA		2006 Actual	2006 Board Approved	Variance
5114	Maintenance of Distribution Station Equipment	397,036	275,086	121,950

A Substation Technician was hired in 2005 to meet the maintenance requirements for the growing number of Municipal Substations. From the years 2004-2006, 7 municipal substation transformers were installed representing a 50% increase in these transformers.

2007 Actual versus 2006 Actual

USoA		2007 Actual	2006 Actual	Variance
5114	Maintenance of Distribution Station Equipment	508,360	397,036	111,324

Copper cable thefts were a major occurrence in 2007 through the GTA and were a recurring problem for Whitby Hydro. As a result, resources were required to repair substation plant as well as reinforce security. The re-configuration of substation grounding conductor work in 2008 acted as a deterrent for further theft.

2008 Actual versus 2007 Actual

USoA		2008 Actual	2007 Actual	Variance
5114	Maintenance of Distribution Station Equipment	306,851	508,360	(201,509)

Costs decreased as a result of the virtual elimination of cable copper thefts. In addition, costs related to the installation of new plant have been charged to substation capital.

USoA		2008 Actual	2007 Actual	Variance
5150	Maintenance of Underground Conductors/Devices	175,145	295,227	(120,082)

Major switchgear repair work was completed in 2007 which was properly classified in 2008.

Billing and Collections

Billing and Collections costs have increased by 23.6% from the 2006 Board Approved amount which is predominately due to inflation combined with increased staff for Customer Service and higher bad debt costs.

Whitby Hydro has experienced considerable growth (49.7%) in its customer base over the past 9 years (1999-2008) and the customer growth rate from 1999-2010 is projected to produce a 52.1% increase. As a result of this growth, Customer Service resources expanded in 2005-2006 and 2008.

Bad debts have increased due to the economic conditions in the Whitby area. The auto industry employs many Whitby residents with General Motors based in Oshawa and several feeder plants in Whitby. In addition, the Ministry of Finance's head offices located in Whitby and Oshawa have undergone major downsizing due to the harmonization of both Provincial Corporate Taxes and Sales Tax which has left many Whitby residents struggling to find new employment.

Table 4-7: Billing and Collections Cost Drivers ($000's)

Appendix 2-H
Billing and Collections Cost driver Table

							2006 Board Approved to 2010 Test Year	
Description/USoA	Note	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Bridge	Total Change $	Total Change %
Opening Balance	1	1,753	2,263	2,300	2,168	2,041	1,753	
Inflation on 2006 Approved costs		84	62	59	59	61	325	18.5%
5315-Customer Billing								
Regulatory costs reclassified to account 5655		(122)					(122)	
Net activity for account 5315		(136)	24	34	10	77	9	
		(258)	24	34	10	77	(113)	-6.4%
5335-Bad Debt Expense		78	(22)	191	(105)	0	142	8.1%
Growth Related								
5340-Miscellaneous Customer Accounts Expenses		124	11	94	(7)	30	252	
Inflation	2	(27)	(20)	(19)	(19)	(19)	(104)	
	3	97	(9)	75	(26)	11	148	8.4%
5415-Energy Conservation		466	81	(547)	0	0	0	
Other		43	(99)	56	(65)	(24)	(89)	-5.1%
		2,263	2,300	2,168	2,041	2,166	2,166	23.6%

Notes:
1. Opening balance for 2006 Actual is the 2006 Board Approved amount.
2. In order to maintain the information at USoA level, variances are reported on a gross basis including inflationary impacts associated with 2006 Approved cost levels. This inflation component has been calculated and removed at the USoA level to avoid duplication with costs which are already included in the inflation line above.
3. USoA costs excluding inflation associated with 2006 approved levels.

The following accounts which exceed the materiality threshold and have been identified in the continuity (Table 4-7) are also explained in greater detail below.

USoA	2006 Actual-2006 Board Approved	2007 Actual-2006 Actual	2008 Actual-2007 Actual	2009 Bridge - 2008 Actual	2010 Test-2009 Bridge
Billing and Collections					
5315-Customer Billing	(258,010)				
5335-Bad Debt Expense			191,411	(104,939)	
5340-Miscellaneous Customer Accounts Expenses	124,102				
5415-Energy Conservation	466,290		(547,418)		

2006 Actual versus 2006 Board Approved

USoA		2006 Actual	2006 Board Approved	Variance
5315	Customer Billing	535,334	793,344	(258,010)
	Reclassification to 5655 - Regulatory Expenses			122,000
	Net activity for account 5315			(136,010)

The Board Approved Regulatory expenses contained OEB fees only. Effective 2005, Regulatory expenses also include internal Regulatory costs. Prior to 2005, these costs were previously grouped with Customer Billing.

USoA		2006 Actual	2006 Board Approved	Variance
5340	Miscellaneous Customer Accounts Expense	686,886	562,784	124,102

Additional Customer Service staff was required to service the increasing number of customers. Whitby Hydro's customer base grew by 44% from 1999 to 2006.

USoA		2006 Actual	2006 Board Approved	Variance
5415	Energy Conservation	466,290	-	466,290

This account records the cost of expenses approved as part of the Third Tranche Conservation and Demand programs. An offsetting amount was recorded as income in 2006. These costs are eliminated in 2008.

2008 Actual versus 2007 Actual

USoA		2008 Actual	2007 Actual	Variance
5335	Bad Debt Expense	304,939	113,528	191,411

Increase in customer payment delinquencies due to economic conditions, specifically two (2) commercial customers (> 50kW) related to the auto industry declared bankruptcy which contributed to the increase.

USoA		2008 Actual	2007 Actual	Variance
5415	Energy Conservation	-	547,418	(547,418)

This account records the cost of expenses approved as part of the Third Tranche Conservation and Demand programs. These costs were incurred from 2006 to 2007 as one time costs.

2009 Bridge Year versus 2008 Actual

USoA		2009 Bridge Year	2008 Actual	Variance
5335	Bad Debt Expense	200,000	304,939	(104,939)

Customer delinquency rate continues to be at a high level, however there have been no large bankruptcies included in 2009, while there were two in 2008.

Administration and General

Administration and General costs have increased by 3.4% from the 2006 Board Approved amount. The continuity below identifies the components which contribute to this change. Increases to these costs are due to Inflation 15.5% and increased compliance requirements 9.4% which are offset by several account reclassifications.

Table 4-8: Administration and General Cost Drivers ($000's)

Appendix 2-H
Administation and General Cost Driver Table

Description/USoA	Note	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2006 Board Approved to 2010 Test Year Total Change $	2006 Board Approved to 2010 Test Year Total Change %
Opening Balance	1	2,799	2,433	2,536	2,513	2,709	2,799	
Inflation on 2006 Approved costs		113	83	79	78	81	434	15.5%
Increase Accounting requirements								
5610-Management Salaries and Expenses		(12)	(56)	126	66	54	178	
Inflation	2	(35)	(26)	(25)	(25)	(25)	(136)	
	3	(47)	(82)	101	41	29	42	1.5%
5645-Employee Pension& Benefits(reclassification)		(183)					(183)	-6.5%
Increased Compliance requirements								
5655-Regulatory Expenses								
Regulatory costs reclassified from account 5315		122					122	
True Net activity for account 5655		21	(14)	31	65	38	141	
Total change for account 5655		143	(14)	31	65	38	263	9.4%
5665-Miscellaneous General Expenses								
Low Voltage - reclassified as regulatory asset		(457)					(457)	
True Net activity for account 5660		129	22	(90)	(34)	4	31	
Total change for account 5660		(328)	22	(90)	(34)	4	(426)	-15.2%
5675-Maintenance of General Plant		(111)	63	(82)	41	7	(82)	-2.9%
Other		47	31	(62)	5	25	46	1.6%
		2,433	2,536	2,513	2,709	2,893	2,893	3.4%

Notes:
1. Opening balance for 2006 Actual is the 2006 Board Approved amount.
2. In order to maintain the information at USoA level, variances are reported on a gross basis including inflationary impacts associated with 2006 Approved cost levels. This inflation component has been calculated and removed at the USoA level to avoid duplication with costs already included in the inflation line above.
3. USoA costs excluding inflation associated with 2006 approved levels.

The following accounts which exceed the materiality threshold and have been identified in the continuity (Table 4-8) are also explained in greater detail below.

USoA	2006 Actual-2006 Board Approved	2007 Actual-2006 Actual	2008 Actual-2007 Actual	2009 Bridge - 2008 Actual	2010 Test-2009 Bridge
Administrative and General					
5610-Management Salaries and Expenses			126,257		
5645-Employee Pensions and Benefits	(183,391)				
5655-Regulatory Expenses	142,525				
5665-Miscellaneous General Expenses	(328,369)				
5675-Maintenance of General Plant	(110,980)				

2006 Actual versus 2006 Board Approved

USoA		2006 Actual	2006 Board Approved	Variance
5645	Employee Pensions and Benefits	-	183,391	(183,391)

Effective 2005, Employee Pensions and Benefits have been allocated directly to OM&A accounts.

USoA		2006 Actual	2006 Board Approved	Variance
5655	Regulatory Expenses	271,883	129,358	142,525
	Reclassification from 5315 - Customer Billing			(122,000)
	Net activity for account 5655			20,525

The Board Approved Regulatory Expenses contained OEB fees only. Effective 2005, Regulatory Expenses also include internal Regulatory costs. Prior to 2005, these costs were previously grouped with Customer Billing.

USoA		2006 Actual	2006 Board Approved	Variance
5665	Miscellaneous General Expenses	398,913	727,282	(328,369)

For the 2006 Board Approved amount, the OEB directed LDCs to include regulatory costs for Hydro One Networks (HONI), which was $475K for Whitby Hydro. Subsequent to this direction, LDCs were asked to flow HONI regulatory costs through account 1584. This variance is a result of the reclassification of HONI costs offset by increased costs due to restructuring and management information system costs (MIS).

USoA		2006 Actual	2006 Board Approved	Variance
5675	Maintenance of General Plant	202,706	313,686	(110,980)

The 2006 Board Approved amount included costs for non-routine maintenance related to a fence rebuild, lighting retrofit and major landscaping work.

2008 Actual versus 2007 Actual

USoA		2008 Actual	2007 Actual	Variance
5610	Management Salaries and Expense	793,372	667,115	126,257

Additional accounting resources were required to manage an increase in the depth of audits; increased outside agencies requiring audits; and the frequency of these audits. These resources also supported an expansion of the internal audit and process review functions.

REGULATORY EXPENSES

Regulatory Expenses include those costs which are necessary to support the requirements of a regulated entity. These costs are captured in USoA account 5655 and include items such as the OEB annual assessment fees, OEB cost awards, license renewal fees, as well as resources and related costs required to support the regulatory environment and its various requirements.

Whitby Hydro has included the costs associated with the 2010 cost of service application in account 5655. As these costs have been prorated over a four year period, the amount included in the test year is the equivalent of ¼ of the total projected cost of $250,000.

Whitby Hydro has summarized the costs as identified in Table 4-9 (Appendix 2-I) of the Board's Filing Requirements.

1 **Table 4-9: Regulatory Cost Schedule (Appendix 2-I)**

Regulatory Cost Schedule

Regulatory Cost Category	USoA Account	Ongoing or One-time Cost?	2006	2007	2008	2009 Bridge Year	% Change in bridge year vs. last year of actuals	2010 Test Year	% Change in Test year vs. Bridge Year
OEB Annual Assessment	5655	ongoing	123,924	128,648	121,610	130,396	7.22%	133,920	2.70%
OEB Section 30 Costs (OEB Initiated)	5655	ongoing	-	6,133	8,209	6,080	-25.93%	6,080	0.00%
Operating expenses associated with staff resources allocated to regulatory matters	5655	ongoing	119,899	122,031	144,200	165,000	14.42%	189,129	14.62%
Other regulatory agency fees or assessments	5655	ongoing	800	800	800	800	0.00%	800	0.00%
Any other costs for regulatory matters - Cost Allocation Informational Filing	5655	one-time	27,260	-	-	-	n/a		n/a
Any other costs for regulatory matters - 2010 Rate Application (Note 1)	5655	one-time	-	-	14,128	51,832	266.88%	62,500	20.58%

Note1: Whitby Hydro estimates the total incremental costs related to its 2010 cost of service rate application will be $250,000. These costs are spread out over a four year period (test year + subsequent three year IRM period). On this basis, a figure of $62,500 has been included in the test year. This projection is assumed to cover costs which include but shall not be limited to consultant fees, legal fees, hearing costs, witness costs etc.

ONE TIME COSTS

Whitby Hydro does not have any significant one time costs included in 2010 Test Year of this rate application.

OM&A COST PER CUSTOMER

The following table provides the detail of average cost per customer.

Appendix 2-J
OM&A Cost per Customer

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Number of Customers	35,146	37,649	38,279	39,226	39,467	39,856
Total OMA	$ 7,201,255	$ 8,161,138	$ 8,727,562	$ 8,149,072	$ 8,485,792	$ 8,919,421
OMA cost per customer	$ 204.90	$ 216.77	$ 228.00	$ 207.75	$ 215.01	$ 223.79

SERVICES EXCHANGED WITH AFFILIATES

OVERVIEW:

The Whitby Hydro group of companies is wholly owned by the Town of Whitby. Whitby Hydro Energy Corporation (Holdco) is the parent company for Whitby Hydro Electric Corporation (Whitby Hydro) and Whitby Hydro Energy Services Corporation (WHES).

Whitby Hydro purchases distribution services under a Services Agreement with its affiliate service provider WHES. A copy of the agreement has been included as Attachment 4-1. The Service Agreement encompasses shared services (corporate services), distribution services as well as other regulated non-utility services such as conservation and demand management (CDM). WHES also provides consulting, engineering, billing and distribution services to other entities.

No Holdco costs are charged to Whitby Hydro and Whitby Hydro's interaction with Holdco is limited to dividend payments. Strategic oversight and governance of Whitby Hydro is provided by the Whitby Hydro Board of Directors.

Whitby Hydro reviews the prices it pays for services provided by the affiliate WHES to ensure they are reasonable and comply with the Affiliate Relationship Code (ARC). To ensure that the service arrangements and pricing were acceptable, a full ARC review was performed by the OEB whereby Whitby Hydro worked closely and cooperatively with Board Staff. Following the review, Whitby Hydro received affirmation of full compliance from the Chief Compliance Officer in December 2006. This compliance confirmation process is described in more detail later in this exhibit. In keeping with the recent changes in the ARC, Whitby Hydro has engaged a third party to perform a review of service arrangements with its affiliate to re-validate the transfer pricing used for services, products and resources.

ACCOUNTING SYSTEMS

At the time of incorporation in 2000, a multi-company general ledger structure was established to record the transactions of Holdco and its subsidiaries. This accounting structure is supported by a job cost system which captures financial transactions at an activity level. The job cost system combines transactions from the Inventory, Payroll, General Ledger and Accounts Payable subsystems. The general ledger structure follows the OEB's USoA requirements.

SHARED SERVICES/CORPORATE COST ALLOCATION:

Shared services between WHES and Whitby Hydro include:

- Finance/General Administration & Human Resources (HR)
- Executive
- Office Supplies
- Outside Services Employed (ie. legal, audit)
- Insurance
- Information Services
- Building Space

Whitby Hydro has identified these services to be important and necessary to operate the utility safely and efficiently. The level of service provided is reviewed annually during the budget process and can be addressed throughout the year should any significant change in need and service levels be identified. Specific cost allocators are identified for each type of service to ensure that they reflect reasonable cost drivers which form the basis of calculating the charges between WHES and Whitby Hydro. By the nature of the sharing of these types of services, Whitby Hydro benefits by avoiding higher costs which would otherwise be incurred if separate and unique resources were required to support the utility on a standalone basis.

The cost allocators identified below outline the methodologies used to allocate the shared services costs.

Shared Service	**Basis of Allocation**
Finance/General Administration	Staff resources spent on activity.
Human Resources (HR)	Allocation based on labour hours.
Executive	Staff resources spent on activity.
Office Supplies	Allocation based on labour hours.
Outside Services Employed (i.e. legal, audit)	Each individual service is reviewed and assigned a percentage allocation based on causality.
Insurance	Review of each insurable item and assigned based on causality.
Information Services	Based on number of users.
Building Space	Allocated based on square footage.

As per the Board’s Filing Requirements, Appendix 2-M has been completed for 2006 – 2010 for all shared services outlined above (Tables 4-10 to 4-14). The table below summarizes the change from 2006 Actual to the 2010 Test Year. The 2010 Test Year has increased by $338k or 19.4% which is predominately due to inflation of 13% combined with higher accounting costs of

4% related to expanding requirements. The percentage of allocated costs has decreased from 86.0% to 83.1% over the 2006-2010 time period. A summary has been provided below.

Summary of Shared Services

Name of Company		Services Offered	Price for the Services ($000s)				% of Costs Allocated ($000s)	
From	To		2006	2010	Var 06-10	Var%	2006	2010
WHES	WH	Information Services (IT)	$ 185	$ 220	$ 35	2.0%	85.6%	86.3%
WHES	WH	Building	$ 203	$ 231	$ 28	1.6%	84.6%	84.3%
WHES	WH	Insurance	$ 102	$ 125	$ 23	1.3%	72.9%	73.1%
WHES	WH	Outside Services	$ 163	$ 239	$ 76	4.4%	91.4%	89.3%
WHES	WH	Executive, Accounting & HR	$ 967	$ 1,161	$ 193	11.1%	90.0%	84.0%
WHES	WH	Office Expenses	$ 125	$ 108	$ (17)	-1.0%	70.7%	68.5%
			$ 1,745	$ 2,083	$ 338	19.4%	86.0%	83.1%

WH = Whitby Hydro Electric Corporation
WHES = Whitby Hydro Energy Services

Table 4-10: 2006 Share Services/Corporate Cost Allocation (Appendix 2-M)

Name of Company		Services Offered	Pricing Methodology	Price for the Service ($000s)	Cost for the Service ($000s)	% Allocation
From	To					
WHES	WH	Information Services (IT)	Cost	$ 185	$ 185	85.6%
WHES	WH	Building	Cost	$ 203	$ 203	84.6%
WHES	WH	Insurance	Cost	$ 102	$ 102	72.9%
WHES	WH	Outside Services	Cost + Rate of Return	$ 163	$ 149	91.4%
WHES	WH	Executive, Accounting & HR	Cost + Rate of Return	$ 967	$ 841	90.0%
WHES	WH	Office Expenses	Cost + Rate of Return	$ 125	$ 109	70.7%
				$ 1,745	$ 1,589	86.0%

WH = Whitby Hydro Electric Corporation
WHES = Whitby Hydro Energy Services

1 **Table 4-11: 2007 Share Services/Corporate Cost Allocation (Appendix 2-M)**

Name of Company From	Name of Company To	Services Offered	Pricing Methodology	Price for the Service ($000s)	Cost for the Service ($000s)	% Allocation
WHES	WH	Information Services (IT)	Cost	$ 190	$ 190	86.0%
WHES	WH	Building	Cost	$ 265	$ 265	85.8%
WHES	WH	Insurance	Cost	$ 115	$ 115	73.6%
WHES	WH	Outside Services	Cost + Rate of Return	$ 126	$ 118	88.1%
WHES	WH	Executive, Accounting & HR	Cost + Rate of Return	$ 987	$ 858	87.5%
WHES	WH	Office Expenses	Cost + Rate of Return	$ 136	$ 118	71.1%
				$ 1,819	$ 1,664	84.6%

WH = Whitby Hydro Electric Corporation
WHES = Whitby Hydro Energy Services

2 **Table 4-12: 2008 Share Services/Corporate Cost Allocation (Appendix 2-M)**

Name of Company From	Name of Company To	Services Offered	Pricing Methodology	Price for the Service ($000s)	Cost for the Service ($000s)	% Allocation
WHES	WH	Information Services (IT)	Cost	$ 218	$ 218	86.1%
WHES	WH	Building	Cost	$ 183	$ 183	81.3%
WHES	WH	Insurance	Cost	$ 119	$ 119	73.9%
WHES	WH	Outside Services	Cost + Rate of Return	$ 196	$ 181	91.9%
WHES	WH	Executive, Accounting & HR	Cost + Rate of Return	$ 1,005	$ 874	85.4%
WHES	WH	Office Expenses	Cost + Rate of Return	$ 98	$ 85	65.5%
				$ 1,818	$ 1,659	83.5%

WH = Whitby Hydro Electric Corporation
WHES = Whitby Hydro Energy Services

1 **Table 4-13: 2009 Share Services/Corporate Cost Allocation (Appendix 2-M)**

Name of Company From	Name of Company To	Services Offered	Pricing Methodology	Price for the Service ($000s)	Cost for the Service ($000s)	% Allocation
WHES	WH	Information Services (IT)	Cost	$ 214	$ 214	85.9%
WHES	WH	Building	Cost	$ 224	$ 224	83.9%
WHES	WH	Insurance	Cost	$ 121	$ 121	72.5%
WHES	WH	Outside Services	Cost + Rate of Return	$ 214	$ 200	88.9%
WHES	WH	Executive, Accounting & HR	Cost + Rate of Return	$ 1,077	$ 962	85.3%
WHES	WH	Office Expenses	Cost + Rate of Return	$ 106	$ 95	67.9%
				$ 1,957	$ 1,816	83.5%

WH = Whitby Hydro Electric Corporation
WHES = Whitby Hydro Energy Services

2 **Table 4-14: 2010 Share Services/Corporate Cost Allocation (Appendix 2-M)**

Name of Company From	Name of Company To	Services Offered	Pricing Methodology	Price for the Service ($000s)	Cost for the Service ($000s)	% Allocation
WHES	WH	Information Services (IT)	Cost	$ 220	$ 220	86.3%
WHES	WH	Building	Cost	$ 231	$ 231	84.3%
WHES	WH	Insurance	Cost	$ 125	$ 125	73.1%
WHES	WH	Outside Services	Cost + Rate of Return	$ 239	$ 226	89.3%
WHES	WH	Executive, Accounting & HR	Cost + Rate of Return	$ 1,161	$ 1,055	84.0%
WHES	WH	Office Expenses	Cost + Rate of Return	$ 108	$ 98	68.5%
				$ 2,083	$ 1,955	83.1%

WH = Whitby Hydro Electric Corporation
WHES = Whitby Hydro Energy Services

OUTSOURCED DISTRIBUTION SERVICES:

Outsourced services between WHES and Whitby Hydro include the following main categories:

- Operations, Maintenance and Administration (OM&A)
- Capital Services
- Vehicle Replacement

Operations, Maintenance and Administration services provide the activities required to support and operate Whitby Hydro's distribution activities. Capital Services are required for the expansion and upgrading of the electrical distribution system. Vehicle Replacement Services are necessary to provide the vehicles and tools used in the OM&A and capital construction activities.

A breakdown of the costs associated with these services is included in table below.

Service	2006 Actual ($000s)	2007 Actual ($000s)	2008 Actual ($000s)	2009 Bridge ($000s)	2010 Test ($000s)
Vehicle replacement	431	452	494	506	532
Capital Services	5,586	6,205	6,210	4,611	7,890
Operation, maintenance and administrative services	4,700	5,060	4,901	5,141	5,498

Allocation Methodology:

As described previously, the accounting structure is supported by a job cost system which captures financial transactions an at an activity level which is built on the USoA foundation. The job cost system combines transactions from the Inventory, Payroll, General Ledger and Accounts Payable subsystems. All staff are required to complete timesheets which facilitates the accumulation of costs on a project and/or functional basis.

OM&A, Capital Services and Vehicle Replacement Services are tracked and actual costs are charged by USoA with an adjustment for no more than the weighted cost of capital.

A test of the transfer pricing covering all of the outsourced and shared services was conducted in 2006 and is outlined in detail in the "Affiliate Relationship Code" section that follows.

REGULATED NON-UTILITY SERVICES:

As referenced in the Service Agreement, WHES has provided services which allow Whitby Hydro to fulfill requirements related to CDM and promote a culture of conservation with customers in the Whitby Hydro distribution service area. These services included resources to develop and implement programs under the Third Tranche spending approved by the OEB, as well as programs defined by the Ontario Power Authority (OPA) and other Whitby Hydro programs which are funded directly by the shareholder. None of these types of activities currently affect the utility specific rates proposed in this application.

A breakdown of the costs associated with these services is included below.

Service	2006 Actual ($000s)	2007 Actual ($000s)	2008 Actual ($000s)	2009 Bridge ($000s)	2010 Test ($000s)
Conservation Demand Management	339	455	213	363	352

Allocation Methodology:

The job cost system tracks costs associated with the various CDM projects. The job cost system, which is built on the USoA structure, captures financial transactions for CDM activities. Labour costs are assigned to the jobs through the use of timesheets. The job cost system combines transactions from the Inventory, Payroll, General Ledger and Accounts Payable subsystems.

CDM services are tracked and actual costs are charged by USoA with an adjustment for no more than the weighted cost of capital.

AFFILIATE RELATIONSHIP CODE:

In order to ensure compliance with the Affiliate Relationships Code (ARC), Whitby Hydro worked collaboratively with the OEB's Chief Compliance Officer (CCO) between 2005 and 2006 as part of an ARC review and on December 1, 2006, received a letter affirming Whitby Hydro's compliance with the ARC. While Whitby Hydro understands that the CCO's views are not binding on the Board, his opinion was based on a comprehensive review of the ARC as it applied specifically to the business activities, corporate structure and shared resources (staff and information) of Whitby Hydro. Since the ARC amendments of May 16, 2008, Whitby Hydro has continued to engage in discussions with the OEB staff regarding ARC interpretations so as to ensure continuing compliance with the ARC.

As a result of the ARC review, Whitby Hydro has embraced the key business practices which anchor the organization with respect to ARC compliancy. These can be summarized as follows:

- Assign at a minimum, one senior level employee within Whitby Hydro to act as an asset manager. Amongst other responsibilities, this individual will negotiate and ensure that services provided by the affiliate are at the agreed to levels and appropriate pricing to ensure compliance with the ARC. This individual operates independently and is not shared by any other affiliates.

- Ensure communication and informational material, provided to customers by Whitby Hydro and any of its affiliates are provided in a manner that allows customers to distinguish between the companies and the services offered.
- WHES has restricted their unregulated activity to business opportunities outside of the Whitby Hydro service area. This approach alleviates any ARC concerns with regards to physical separation or sharing of employees or information.
- Transfer pricing reviews apply the same approach taken during the CCO's ARC review. During the ARC review, the CCO and Whitby Hydro performed departmental reviews to:
    - Identify costs that were charged directly to Whitby Hydro.
    - Identify shared corporate services.
    - Identify the remaining WHES provided materials and services to determine where a market exists and complete the required market price testing.
    - Identify outsourced work activities and materials which were procured by WHES for Whitby Hydro. These costs were price tested against a scenario whereby Whitby Hydro procured the work directly.
- Where no market exists and market price testing is not feasible, WHES charges Whitby Hydro no more than the fully allocated cost which may include a return on invested capital at a rate no higher than Whitby Hydro's weighted average cost of capital.

Whitby Hydro continues to rely on the operating rules and market price validation approved by the CCO and the independence of its Board of Directors and V.P. (Asset Manager) to ensure appropriate pricing and ARC compliance.

1 # PURCHASES OF NON-AFFILIATE SERVICES

2 The following table outlines the purchases of non-affiliate services that annually exceed the
3 materiality threshold of $103,736 by year for the time period of 2006-2010.

NAME	SUPPLIER LIST>$103,000 ACTIVITY	SELECTION PROCESS	DOLLAR AMOUNT
2010			
Sonepar	Conservation Activities	RFP	390,000
K.T.I.	Smart Meters	London RFP	4,640,000
M.E.A.R.I.E.	Liability and Property Insurance	Reciprocal	150,000
Clean Air Foundation	Conservation Activities	RFP	130,000
Insight Canada	Computer Hardware and Software	RFQ	105,000
Olameter	Smart Meter Installation	London RFP	480,000
Sensus	Smart Meter- System operations	London RFP	120,000
2009			
Sonepar	Conservation Activities	RFP	393,374
K.T.I.	Smart Meters	London RFP	248,000
M.E.A.R.I.E.	Liability and Property Insurance	Reciprocal	146,087
Clean Air Foundation	Conservation Activities	RFP	131,023
Insight Canada	Computer Hardware and Software	RFQ	110,000
Intergraph	AM/FM system	Single Source	105,000
2008			
K.T.I.	Smart Meters- Base Station	London RFP	302,400
M.E.A.R.I.E.	Liability and Property Insurance	Reciprocal	156,197
Insight Canada	Computer Hardware and Software	RFQ	118,925
Intergraph	AM/FM system	Single Source	116,467
ITRON	Meters	RFQ	103,170
2007			
M.E.A.R.I.E.	Liability and Property Insurance	Reciprocal	154,294
2006			
M.E.A.R.I.E.	Liability and Property Insurance	Reciprocal	140,614
General Electric Multilin Inc.	SCADA Installation	Single Source	112,677
BDO Dunwoody	Software and Installation- Financial System	RFQ	141,419

DEPRECIATION, AMORTIZATION AND DEPLETION:

In accordance with the CICA Handbook, Whitby Hydro uses the straight-line method of amortization. Capital assets are recorded at cost and amortized over their estimated service lives using the straight-line method of amortization. Whitby Hydro does not capitalize the interest to the costs of the assets constructed. Whitby Hydro uses the pooling of assets for fixed assets.

A full year's amortization is taken on capital additions during the current year which has been consistently applied and accepted by external auditors since Whitby Hydro's inception. A similar amortization policy was approved by the Board in their decision on the Collus Power Corporation's cost of service application, EB-2008-0226, on April 17, 2009.

Depreciation rates are in line with rates set out in the OEB's Accounting Procedures Handbook (APH). A summary of those rates are as follows in Table 4-15.

Table 4-15: Depreciation Rates

1808	Buildings	2.0%
1908	Buildings	2.0%
1815	Transformer Station Equipment > 50kV	2.5%
1820	Distribution Station Equipment < 50kV	3.3%
1830	Poles, Towers and Fixtures	4.0%
1835	Overhead Conductors	4.0%
1840	Underground Conduit	4.0%
1845	Underground Conductors and Devices	4.0%
1850	Line Transformers	4.0%
1855	Services	4.0%
1860	Metering	4.0%
1915	Furniture and Equipment	10.0%
1920	Computer Hardware	20.0%
1925	Computer Software	20.0%
1930	Transportation Equipment < 3 Tonnes	20.0%
1930	Transportation Equipment > 3 Tonnes	12.5%
1935	Stores Equipment	10.0%
1940	Tools, Shop and Garage Equipment	10.0%
1945	Measurement and Testing Equipment	10.0%
1950	Power Operated Equipment	12.5%
1955	Communication Equipment	10.0%
1960	Miscellaneous Equipment	20.0%
1980	System Supervisory Equipment	6.7%
1995	Contributed Capital	4.0%

Details of Whitby Hydro's amortization by account number are provided in the Fixed Asset Continuity Schedules in Exhibit 2, Schedules 2-1 to 2-5.

Amortization expense has increased by 40.9% from 2006 Board Approved to 2010 Test Year due to the significant expansion of the distribution system required to meet customer growth.

Amortization Expense

USoA	Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
5705	Amortization Expense - Property, Plant, and Equipment	3,497,331	3,896,885	4,128,556	4,401,237	4,582,515	4,929,391
	Change -Year over Year		399,554	231,671	272,681	181,278	346,876
	% Change -Year over Year		11.42%	5.95%	6.60%	4.12%	7.57%
	% Change Test Year to Most Current Actual (2010 vs. 2008)						12.00%
	% Change Test Year to 2006 Board Approved						40.95%
	Average % Change						6.82%
Total		**3,497,331**	**4,296,439**	**4,360,227**	**4,673,918**	**4,763,793**	**5,276,267**

The sum of the 2005 to 2010 net capital additions as a percentage of the 2006 Board Approved Fixed assets of $96,147,000 is 40. 72 % and supports the increase in amortization expense.

2005-2010 Net Capital Additions as a % of 2006 Board approved Fixed Assets

Description	2005 Actual	2006 Actual	2007 Actual	2008 Bridge	2009 Bridge	2010 Test	Total
Net Capital Additions	4,588,000	6,470,000	6,800,000	7,504,000	5,383,000	8,409,000	39,154,000
2006 Board Approved-Fixed Assets							96,147,000
% Net Capital Additions to 2006 Board Approved- Fixed Assets							40.72%

PAYMENTS-IN-LIEU OF INCOME TAXES (PILS)

Whitby Hydro is subject to the payment of PILs under Section 93 of the Electricity Act, 1998, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Table 4-16 provides a summary of 2006 OEB Approved, 2006 to 2008 income taxes included in audited statements, 2009 bridge year estimate using current rates, and 2010 test year income taxes based on revised rates. A copy of the 2008 Federal T2 and Ontario C23 tax return has been provided in Attachment 4-2. PILS amounts included in the 2008 financial statements are based on estimates and will differ from the actual PILS return. The difference between actual and estimate will be recorded in the 2009 financial statements.

Tax Calculation

Whitby Hydro has used the most recent tax rates available at present, which are provided in Table 4-17. Whitby Hydro is not subject to the Federal Large Corporation Tax. Whitby Hydro has calculated PILS using the Board approved method which is summarized in Table 4-16 and detailed calculations are shown in Table 4-19.

Capital Cost Allowance (CCA)

Whitby Hydro presents the calculations for CCA for the 2009 Bridge Year and the 2010 Test Year in Table 4-20. In addition, the 2008 Actual CCA has been adjusted to remove Smart Meter additions. As a result, the 2009 UCC Opening balance does not contain any Smart Meter UCC.

Cumulative Eligible Capital Deduction

The October 1, 2001 Fair Market Value (FMV) bump has been included in the calculation of the Cumulative Eligible Capital Deduction (see Table 4-21).

Capital Taxes

The 2010 Test Year rate base of $75,799,437 has been used as the regulatory value of 2010 taxable capital for the calculation of Ontario Capital Tax. The full amount of the OCT exemption has been claimed.

Loss Carry-Forwards

There are no loss carry forward amounts available for use in the calculation of 2010 Test Year.

Property Taxes

The tax model addresses only corporate income and capital taxes. Property taxes have been included as a distribution expense as per section 7.2.14 of the 2006 Rate EDR Handbook.

Table 4-16: Summary of PILS

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Income Taxes	1,100,560	2,503,446	3,097,337	2,659,137	1,172,483	793,034
Large Corporation Tax						
Ontario Capital Tax	151,793	177,451	171,299	135,697	131,818	45,600
Total Taxes	**1,252,354**	**2,680,897**	**3,268,636**	**2,794,834**	**1,304,301**	**838,633**

Regulatory Assets/Liabilities

For purposes of GAAP and Income Taxes, current year changes to regulatory assets/liabilities flow through the income statement. As a result, 2006- 2008 actual taxes payable are significantly higher due revenue recognized from regulatory liabilities i.e. 2008 $3,416K, 2007 $4,532K and 2006 $2,155K. The PILS expense for regulatory purposes does not follow this treatment as changes to regulatory assets/liabilities are reflected on the balance sheet.

Table 4-17: Corporate Tax Rates

Corporate Tax Rates

Corporate Tax Rates for Tax Year	2009 Bridge	2010 Test
OCT Exemption	15,000,000	15,000,000
Federal Income Tax	19.0%	18.0%
Ontario Income Tax	14.0%	13.0%
Combined Income Tax	33.0%	31.0%
Ontario Capital Tax Rate	0.225%	0.1%

Table 4-18: Summary of Income Taxes

Description	2006 Board Approved	2009 Bridge	2010 Test
Income Taxes	1,100,560	1,172,483	793,034
Ontario Capital Tax	151,793	131,818	45,600
Total Taxes	**1,252,354**	**1,304,301**	**838,633**

Total PILS Expense(Grossed up)	2006 Board Approved	2009 Bridge	2010 Test
Income Tax Payable	1,100,560	1,172,483	793,034
Total CorporateTax Rate	36.12%	33.00%	31.00%
Grossed-up Income Tax	**1,722,856**	**1,749,975**	**1,149,324**
Ontario Capital Tax	**151,793**	**131,818**	**45,600**
Total PILS Expense	**1,874,649**	**1,881,793**	**1,194,924**

Table 4-19: Tax Calculations

Description	2006 Board Approved	2009 Bridge	2010 Test
Determination of Taxable Income			
Utility Income Before Taxes	2,726,901	3,558,762	2,428,614
Book to Tax Adjustments			
Additions to Accounting Income:			
Amortization of tangible assets	3,497,331	4,582,515	4,929,391
Charitable donations			
Non-deductible meals and entertainment expense			
Other Additions			
Total Additions	**3,497,331**	**4,582,515**	**4,929,391**
Deductions to Accounting Income:			
Gain on disposal of assets per financial statements			
Capital cost allowance	3,104,681	4,533,529	4,748,903
Other deductions	72,596	54,769	50,935
Total Deductions	**3,177,277**	**4,588,298**	**4,799,838**
Regulatory Taxable Income	**3,046,955**	**3,552,979**	**2,558,167**
Federal Corporate Income Tax Rate	22.12%	19.00%	18.00%
Provincial Corporate Income Tax Rate	14.00%	14.00%	13.00%
Total CorporateTax Rate	**36.12%**	**33.00%**	**31.00%**
Regulatory Income Tax	**1,100,560**	**1,172,483**	**793,034**
Calculation of Utility Income Taxes			
Income Taxes	1,100,560	1,172,483	793,034
Ontario Capital Tax	151,793	131,818	45,600
Total Taxes	**1,252,354**	**1,304,301**	**838,633**
Calculation of Ontario Capital Tax			
Total Rate Base	60,597,801	73,585,711	75,799,437
Less: Exemption	10,000,000	15,000,000	15,000,000
Taxable Capital/Deemed Taxable Capital	**50,597,801**	**58,585,711**	**60,799,437**
OCT Rate	0.300%	0.225%	0.075%
Ontario Capital Tax	**151,793**	**131,818**	**45,600**

Table 4-20: CCA Continuity Schedules (2008 – 2010)

CCA Continuity Schedule (2008)

Class	Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Yr Rule (1/2 Additions less Disposals)	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - post 1987	43,315,404	0	0	43,315,404	0	43,315,404	4%	1,732,616	41,582,788
2	Distribution System - pre 1988	9,188,702		0	9,188,702	0	9,188,702	6%	551,322	8,637,380
8	General Office/Stores Equip	2,207,625	820,864	0	3,028,489	410,432	2,618,057	20%	523,611	2,504,878
10	Computer Hardware/ Vehicles	132,216		0	132,216	0	132,216	30%	39,665	92,551
12	Computer Software	38,280	82,034	0	120,314	41,017	79,297	100%	79,297	41,017
17	Yard Improvements	191,309	0	0	191,309	0	191,309	8%	15,305	176,004
45	Computers & Systems Software acq'd post Mar 22/04	122,192	0	0	122,192	0	122,192	45%	54,986	67,206
47	Distribution System - post February 2005	11,119,311	6,612,837	0	17,732,148	3,306,419	14,425,730	8%	1,154,058	16,578,090
50	Data Network Infrastructure Equipment - post Mar 2007		324,643	0	324,643	162,322	162,322	55%	89,277	235,366
95			606,500		606,500	303,250				606,500
	SUB-TOTAL-UCC	66,315,039	8,446,878	0	74,761,917	4,223,439	70,235,228		4,240,138	70,521,779

Smart Meter Component of CCA

8	General Office/Stores Equip		312,165	0	312,165	156,083	156,083	20%	31,217	280,949
50	Data Network Infrastructure Equipment - post Mar 2007		24,030	0	24,030	12,015	12,015	55%	6,608	17,422
95			606,500							

CCA Continuity Schedule (2008)- Net of Smart Meter Activity

Class	Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Yr Rule (1/2 Additions less Disposals)	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - post 1987	43,315,404	0	0	43,315,404	0	43,315,404	4%	1,732,616	41,582,788
2	Distribution System - pre 1988	9,188,702		0	9,188,702	0	9,188,702	6%	551,322	8,637,380
8	General Office/Stores Equip	2,207,625	508,699	0	2,716,324	254,350	2,461,975	20%	492,395	2,223,929
10	Computer Hardware/ Vehicles	132,316		0	132,316	0	132,316	30%	39,695	92,621
12	Computer Software	38,280	82,034	0	120,314	41,017	79,297	100%	79,297	41,017
17	Yard Improvements	191,409	0	0	191,409	0	191,409	8%	15,313	176,096
45	Computers & Systems Software acq'd post Mar 22/04	122,192	0	0	122,192	0	122,192	45%	54,986	67,206
47	Distribution System - post February 2005	11,119,311	6,612,837	0	17,732,148	3,306,419	14,425,730	8%	1,154,058	16,578,090
50	Data Network Infrastructure Equipment - post Mar 2007		300,613	0	300,613	150,307	150,307	55%	82,669	217,944
95			0							
	SUB-TOTAL-UCC	66,315,239	7,504,183	0	73,819,422	3,752,092	70,067,331		4,202,351	69,617,071

CCA Continuity Schedule (2009)

Class	Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Yr Rule (1/2 Additions less Disposals)	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - post 1987	41,582,788	0	0	41,582,788	0	41,582,788	4%	1,663,312	39,919,476
2	Distribution System - pre 1988	8,637,380	0	0	8,637,380	0	8,637,380	6%	518,243	8,119,137
8	General Office/Stores Equip	2,223,929	229,200	0	2,453,129	114,600	2,338,529	20%	467,706	1,985,423
10	Computer Hardware/ Vehicles	92,621		0	92,621	0	92,621	30%	27,786	64,835
12	Computer Software	41,017	44,000	0	85,017	22,000	63,017	100%	63,017	22,000
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	176,096	0	0	176,096	0	176,096	8%	14,088	162,009
45	Computers & Systems Software acq'd post Mar 22/04	67,206	0	0	67,206	0	67,206	45%	30,243	36,963
47	Distribution System - post February 2005	16,578,090	4,932,000	0	21,510,090	2,466,000	19,044,090	8%	1,523,527	19,986,562
50	Data Network Infrastructure Equipment - post Mar 2007	217,944		0	217,944	0	217,944	55%	119,869	98,075
50	Data Network Infrastructure Equipment - post Mar 2007	0	177,800	0	177,800	88,900	88,900	100%	88,900	88,900
	SUB-TOTAL-UCC	69,617,071	5,383,000	0	75,000,071	2,691,500	72,308,571		4,516,690	70,483,381

CCA Continuity Schedule (2010)

Class	Description	UCC Bridge Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Yr Rule (1/2 Additions less Disposals)	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - post 1987	39,919,476	0	0	39,919,476	0	39,919,476	4%	1,596,779	38,322,697
2	Distribution System - pre 1988	8,119,137	0	0	8,119,137	0	8,119,137	6%	487,148	7,631,989
8	General Office/Stores Equip	1,985,423	292,000	0	2,277,423	146,000	2,131,423	20%	426,285	1,851,139
10	Computer Hardware/ Vehicles	64,835		0	64,835	0	64,835	30%	19,450	45,384
12	Computer Software	22,000	164,000	0	186,000	82,000	104,000	100%	104,000	82,000
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	162,009	0	0	162,009	0	162,009	8%	12,961	149,048
45	Computers & Systems Software acq'd post Mar 22/04	36,963	0	0	36,963	0	36,963	45%	16,633	20,330
47	Distribution System - post February 2005	19,986,562	7,897,000	0	27,883,562	3,948,500	23,935,062	8%	1,914,805	25,968,757
50	Data Network Infrastructure Equipment - post Mar 2007	98,075		0	98,075	0	98,075	55%	53,941	44,134
50	Data Network Infrastructure Equipment - post Mar 2007	88,900	56,000		144,900	28,000	116,900	100%	116,900	28,000
	SUB-TOTAL-UCC	70,483,381	8,409,000	0	78,892,381	4,204,500	74,687,881		4,748,903	74,143,478

Table 4-21: Cumulative Eligible Capital

Cumulative Eligible Capital Calculation	2006 Board Approved	2009 Bridge	2010 Test
Cumulative Eligible Capital	1,037,091	782,416	727,647
Additions			
Deductions			
Cumulative Eligible Capital Balance	1,037,091	782,416	727,647
CEC Deduction - 7%	**72,596**	**54,769**	**50,935**
Cumulative Eligible Capital-Closing Balance	964,495	727,647	676,712

ATTACHMENTS

Attachment 4-1: Service Agreements

Attachment 4-2: Corporate Tax Return, 2008

SERVICES AGREEMENT

THIS AGREEMENT made this 1st day of January, 2010

BETWEEN:

(Whitby Hydro Energy Services Corporation)

(hereinafter referred to as the Energy Services Corporation)
OF THE FIRST PART

- and –

(Whitby Hydro Electric Corporation)

(hereinafter referred to as The Electric Corporation)
OF THE SECOND PART

WHEREAS THE ENERGY SERVICES CORPORATION and THE ELECTRIC CORPORATION are duly incorporated Ontario business corporations pursuant to s. 142 of the *Electricity Act, 1998;*

AND WHEREAS both THE ENERGY SERVICES CORPORATION and THE ELECTRIC CORPORATION are, as separate but affiliated corporate entities, governed by the *Affiliate Relationship Code;*

AND WHEREAS the Parties have agreed that THE ENERGY SERVICES CORPORATION will build, operate, maintain and repair THE ELECTRIC CORPORATION's electrical distribution system on a fee-for-service basis.

AND WHEREAS the Parties acknowledge and agree that in providing goods and services THE ENERGY SERVICES CORPORATION acts as an independent contractor and not as an agent, partner, or servant;

AND WHEREAS the Parties shall consult as frequently as may be desirable to ensure that THE ELECTRIC CORPORATION and its customers receive adequate, economical and effective electrical distribution and related services;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good valuable consideration and the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, and with each other, as follows:

1. Definitions

1.01 **"Capital Cost"** means the cost incurred for materials, equipment, overhead, and labour to provide Capital Works.

1.02 **"Capital Works"** means those expansions and upgrades to THE ELECTRIC CORPORATION's electrical distribution system as may be agreed from time to time pursuant to Article 4.01 of this Agreement.

1.03 **"Customer Service Costs"** means the cost incurred by a Party to bill and collect and to provide related customer services. These costs shall be included in the fees and charges for **"O.M.&A. Costs"**.

1.04 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing, collection of unpaid accounts, and customer relations, etc.

1.05 **"Direct Costs"** means the cost incurred directly by THE ELECTRIC CORPORATION for its own operations including but not limited to electrical power costs for Standard Supply Service, IMO costs, Hydro One Transmission costs and Competition Transition Charges.

1.06 **"Easements"** means any permissions, concessions, permits, licenses, interests, ways, privileges, easements and right-of-way to install, operate and maintain part or parts of the electrical distribution system over real property.

1.07 **"Extraordinary Costs"** means unusual and unanticipated costs.

1.08 **"O.M.&A. Costs"** means operations, maintenance and administration costs incurred by THE ENERGY SERVICES CORPORATION to distribute electric power within THE ELECTRIC CORPORATION's geographic territory.

1.09 **"Transition Costs"** means one-time costs of reconfiguring or adding any system, policy, procedure, legal arrangement, employee relationship, etc. necessary for the Parties to operate under this Agreement and under electric utility industry restructuring as defined in *The Energy Competition Act, 1998* and its associated regulations.

1.10 **"Vehicle and Tools Cost"** means the cost of trucks and other motorized vehicles, and tools used in operations, maintenance, administration and capital works of THE ELECTRIC CORPORATION.

1.11 **"Conservation/Demand Management Costs"** means the cost incurred by the ENERGY SERVICES CORPORATION in administering on behalf of the ELECTRIC CORPORATION the approved Ontario Energy Board/Ontario Power Authority programs.

2. Term

2.01 Unless terminated in accordance with Article 10.01, the term of this Agreement shall be from January 1, 2010 to and including December 31, 2014 and the term shall be extended automatically for further periods of one year each, unless either Party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Electrical Distribution Maintenance Services

3.01 THE ENERGY SERVICES CORPORATION agrees to maintain in a good and workmanlike manner THE ELECTRIC CORPORATION's electrical distribution system in the areas serviced by THE ELECTRIC CORPORATION.

4. Capital Works

4.01 THE ENERGY SERVICES CORPORATION shall expand or upgrade in a timely way and in a good and workmanlike manner THE ELECTRIC CORPORATION's electrical distribution system at THE ELECTRIC CORPORATION's request, which shall hereinafter be referred to as "Capital Works" provided that such Capital Works have been designed in accordance with good engineering principles applicable in the Province of Ontario.

5. Costs

O.M.&A. Costs

5.01 The Electric Corporation agrees to pay the Energy Services Corporation on a monthly basis the fees and charges for the operation, maintenance and administration costs (O.M.&A. costs) to maintain the Electric Corporation's distribution system which will be approved by the Board of Directors and readjusted on an annual basis. Without limiting the generality of the foregoing, THE ENERGY SERVICES CORPORATION shall also provide, an accounting of all actual costs, including labour, equipment and material costs, engineering design and review costs which shall include an adjustment for the weighted average cost of capital. THE ENERGY SERVICES CORPORATION will then refund or charge THE ELECTRIC CORPORATION for the variance.

Vehicle/Tool Costs

5.02 THE ELECTRIC CORPORATION shall pay THE ENERGY SERVICES CORPORATION on a monthly basis the fees and charges which will be approved by the Board of Directors and readjusted on an annual basis, as THE ELECTRIC CORPORATION's contribution towards the acquisition of trucks, other motorized vehicles and tools used by THE ENERGY SERVICES CORPORATION. The Energy Services Corporation shall provide, an accounting of all actual costs which shall include an adjustment for the weighted average cost of capital. The Energy Services Corporation will then refund or charge the Electric Corporation for the variance.

Conservation/Demand Management Costs

5.03 The ELECTRIC CORPORATION shall pay to the ENERGY SERVICES CORPORATION on a monthly basis the charges which will be approved by the Board of Directors and readjusted on an annual basis. The ENERGY SERVICES CORPORATION shall provide, an accounting of all costs which shall include an adjustment for the weighted average cost of capital. The ENERGY SERVICES CORPORATION will then refund or charge the ELECTRIC CORPORATION for the variances.

Direct Costs

5.04 THE ELECTRIC CORPORATION's direct costs shall all be paid by the THE ELECTRIC CORPORATION.

Capital Works Costs

5.05 THE ELECTRIC CORPORATION agrees to pay to THE ENERGY SERVICES CORPORATION on a monthly basis the charges for capital works, which will be approved by the Board of Directors and readjusted on an annual basis. Without limiting the generality of the foregoing, THE ENERGY SERVICES CORPORATION shall provide, an accounting of all actual costs, including labour, equipment and material costs, engineering design and review costs which shall include an adjustment for the weighted average cost of capital. THE ENERGY SERVICES CORPORATION will then refund or charge THE ELECTRIC CORPORATION for the variance.

Extraordinary Costs

5.06 THE ELECTRIC CORPORATION agrees to reimburse THE ENERGY SERVICES CORPORATION for any extraordinary costs over and above normal O.M.&A., Customer Service and Capital Works Costs to which THE ENERGY SERVICES CORPORATION may incur resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of THE ENERGY SERVICES CORPORATION to provide routine service and maintenance of the electrical distribution system.

Transition Costs

5.07 THE ENERGY SERVICES CORPORATION shall charge THE ELECTRIC CORPORATION for transition costs associated with both electric utility industry restructuring and the transfer of THE ELECTRIC CORPORATION's operations to THE ENERGY SERVICES CORPORATION.

Renewal

5.08 Upon renewal of the term of this Agreement and any subsequent renewals, THE ENERGY SERVICES CORPORATION may adjust the O.M.&A., Vehicle and Equipment Costs, Capital Works Costs and Extraordinary Costs upon ninety (90) days prior notice in writing to THE ELECTRIC CORPORATION provided that, if THE ELECTRIC CORPORATION does not accept the adjusted costs and the Parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to paragraph 12 of this agreement.

6/ Payments

6.01 THE ELECTRIC CORPORATION shall pay the ENERGY SERVICES CORPORATION on a monthly basis for the services outlined in this agreement. All charges shall be paid by THE ELECTRIC CORPORATION within ten (10) days from the date of receipt.

6.02 THE ENERGY SERVICES CORPORATION will submit details of any extraordinary costs to THE ELECTRIC CORPORATION for review before the charges are processed. Charges of extraordinary costs will be paid by THE ELECTRIC CORPORATION within ten (10) days of receipt.

7. Easements

7.01 THE ELECTRIC CORPORATION represents that it has secured all requisite Easements necessary for the delivery of electrical services for the distribution of electric power throughout the Electric Corporation service area.

7.02 THE ELECTRIC CORPORATION shall indemnify and save THE ENERGY SERVICES CORPORATION harmless from any claims, demands, actions and applications brought against THE ENERGY SERVICES CORPORATION arising from the failure of THE ELECTRIC CORPORATION to have secured Easements or from any defect or deficiency in the Easements secured by THE ELECTRIC CORPORATION prior to the effective date of this Agreement.

7.03 If further Easements are required for the distribution of electric power throughout the the ELECTRIC CORPORATION service area, THE ELECTRIC CORPORATION shall acquire such Easements at its expense provided that prior to acquiring such Easements, THE ELECTRIC CORPORATION shall consult with THE ENERGY SERVICES CORPORATION to determine THE ENERGY SERVICES CORPORATION's minimum technical requirements for such Easements.

7.04 After the effective date of this Agreement, THE ENERGY SERVICES CORPORATION shall act on behalf of THE ELECTRIC CORPORATION to secure all Easements required for the performance of the expansion or upgrade of electrical distribution services pursuant to this Agreement. Any costs related to the acquisition of Easements, including appraisal and legal costs, shall be paid by THE ELECTRIC CORPORATION.

8. Customer Billing

8.01 THE ENERGY SERVICES CORPORATION shall bill THE ELECTRIC CORPORATION's customers for electricity supplied to them but such bills shall be issued in THE ELECTRIC CORPORATION's name.

8.02 THE ELECTRIC CORPORATION shall be responsible for all costs related to any billing errors and uncollectable electricity bills incurred on or before the commencement of this Agreement and shall indemnify and save THE ENERGY SERVICES CORPORATION harmless in respect thereof.

8.03 THE ENERGY SERVICES CORPORATION shall assume responsibility for any billing errors arising after the commencement of this Agreement only to the extent that the electricity costs arising from the billing errors are unrecoverable from THE ELECTRIC CORPORATION's customer and only if the billing error is attributable to THE ENERGY SERVICES CORPORATION's negligence or the negligence of its servants, agents or representatives.

9. Arbitration

9.01 The Parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either Party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the Parties agree to resolve their disputes by arbitration as provided in paragraph 9.02.

9.02 Arbitration of a dispute shall be commenced by written notice by a Party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

9.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

9.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

9.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

10. Termination

10.01 In the event of non-performance by either Party of its obligations under this Agreement, the other Party may at its sole option elect to terminate this Agreement provided that the defaulting Party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

11. Insurance

11.01 THE ELECTRIC CORPORATION and THE ENERGY SERVICES CORPORATION shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the services performed by THE ENERGY SERVICES CORPORATION under the terms of this Agreement.

11.02 THE ELECTRIC CORPORATION agrees to endorse its insurance coverage with THE ENERGY SERVICES CORPORATION as an additional named insured to cover any liability of THE ENERGY SERVICES CORPORATION resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of THE ENERGY SERVICES CORPORATION, or to those for whom THE ENERGY SERVICES CORPORATION is at law responsible.

11.03 THE ENERGY SERVICES CORPORATION agrees to endorse its insurance coverage with THE ELECTRIC CORPORATION as an additional named insured to cover any liability of THE ELECTRIC CORPORATION resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of THE ELECTRIC CORPORATION, or to those for whom THE ELECTRIC CORPORATION is at law responsible.

11.04 All policies shall contain a clause requiring the insurer to give THE ENERGY SERVICES CORPORATION or THE ELECTRIC CORPORATION, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

11.05 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

12. Warranty

12.01 THE ENERGY SERVICES CORPORATION provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

13. Notices:

13.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the Corporate Secretary, THE ENERGY SERVICES CORPORATION at P.O. Box 59, 100 Taunton Road E., Whitby, Ontario L1N 5R8
b) to the Corporate Secretary, THE ELECTRIC CORPORATION at P.O. Box 59, 100 Taunton Road, Whitby, Ontario L1N 5R8

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

14. Amendments:

14.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

15. Headings:

15.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

16. Governing Law:

16.01 This Agreement shall be construed in accordance with the laws of the Province of Ontario.

17. Successors

17.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

17.02 For the purposes of this Agreement, whenever the term THE ENERGY SERVICES CORPORATION or THE ELECTRIC CORPORATION is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

18. Regulatory Changes:

18.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the Parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 9.

19. Relationship:

19.01 The Parties acknowledge and agree that THE ENERGY SERVICES CORPORATION shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between THE ENERGY SERVICES CORPORATION and THE ELECTRIC CORPORATION .

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

THE ENERGY SERVICES CORPORATION
Per:
R. Abi-Rashed
Treasurer

THE ELECTRIC CORPORATION
Per:
J. E. Lavelle, P. Eng.
President

Attachment 4-2: 2008 Corporate Tax Return

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.

AMENDED

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☐ Yes ☒ No

Page 1 of 20

Corporation's Legal Name *(including punctuation)*: Whitby Hydro Electric Corporation

Ontario Corporations Tax Account No. (MOF): 1800225

Mailing Address:
100 Taunton Road East
PO Box 59
Whitby
ON CA L1N 5R8

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): 2000-11-01

Registered/Head Office Address:
100 Taunton Road East
PO Box 59
Whitby
ON CA L1N 5R8

Ontario Corporation No. (MGS):

Location of Books and Records:
100 Taunton Road East
PO Box 59
Whitby
ON CA L1N 5R8

Canada Revenue Agency Business No. (If applicable, enter): 86477 3395 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
RAMONA ABI-RASHED	(905) 668-5878	

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):
☒ *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* ☒ *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*: ☒ English *anglais* ☐ French *français*

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):

Ministry Use

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). ▶ ☒ No Change

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)*

Title D ☐ Director O ☒ 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.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

CT23 Corporations Tax Return

Identification 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 [X] 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.)

[X] 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.)

Specify major business activity

Income Tax

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	7,708,231
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 704	
Net capital losses (page 16) From 715 4,760 x inclusion rate 50.000000 % =	–	714	2,380
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	7,705,851

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	7,705,851

Taxable Income

Number of Days in Taxation Year

From	Amount		Ontario Allocation		Rate		Days		Total Days			
10 (or 20 if applicable)	7,705,851	x 30	100.0000 %	x	12.5 %	x	33 (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷ 73	366	= +	29	
10 (or 20 if applicable)	7,705,851	x 30	100.0000 %	x	14 %	x	34 (Days after Dec. 31, 2003) 366	÷ 73	366	= +	32	1,078,819

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 1,078,819

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	7,705,851
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	7,705,851		
Add: Losses of other years deducted for federal purposes (fed.s.111)	+ 52	2,380		
Subtract: Losses of other years deducted for Ontario purposes (s.34)	– 53	2,380		
	=	7,705,851	54	7,705,851
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 [31 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ______ ÷ ** 366] = + 46 ________

400,000 x [34 (Days after Dec. 31, 2003) 366 ÷ ** 366] = + 47 ________

Business Limit for Ontario purposes 46 + 47 = 44 500,000 x 48 100.0000 % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = 45 500,000

Income eligible for the IDSBC From 30 100.0000 % (***Ontario Allocation) x 56 500,000 (Least of 50, 54 or 45) = 60 500,000

* ***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

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate - - - 7 % x [31] (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ [73] 366 (Total Days) = + [89] .

8.5 % x [34] 366 (Days after Dec. 31, 2003) ÷ [73] 366 (Total Days) = + [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] 7,705,851

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)
Whitby Hydro Services Corp	1800227	2008-12-31	+ [82]	2,718,908
Whitby Hydro Energy Corporation	1800226	2008-12-31	+ [83]	
			+ [84]	

Aggregate Taxable Income [80] + [82] + [83] + [84], etc. - - - = [85] 10,424,759

Number of Days in Taxation Year

320,000 x [31] (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ [73] 366 (Total Days) = + [115]

400,000 x [34] 366 (Days after Dec. 31, 2003) ÷ [73] 366 (Total Days) = + [116]

[115] + [116] = 500,000 - - - − [114] 500,000

(If negative, enter nil) - - - = [86] 9,924,759

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax - - - 4.6670 % x [38] (Days after Dec. 31, 2002) ÷ [73] 366 (Total Days) = + [97] 4.2500

From [86] 9,924,759 x From [97] 4.2500 % - - - = [87] 421,802

From [87] 421,802 x From [60] 500,000 ÷ From [114] 500,000 = [88] 421,802

Surtax Lesser of [70] or [88] - - - = [100] 42,500

**** Note: 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] .

Manufacturing 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]	7,705,851 .
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] 7,705,851 X Allocation % to jurisdictions outside Canada	–	[140]	.
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses	–	[141]	.
[10] – [56] + [122] – [140] – [141]	=	[142]	7,705,851 .

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] 1,078,819 .

continued on Page 7

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

DOLLARS ONLY

Income Tax *continued from Page 6*

Specified 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

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. 204 Name of Production
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 194
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.
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)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible 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 202
Applies to employment of eligible apprentices.
Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) + 203

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits ***Applied to reduce Income Tax*** = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 1,078,819

To 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	85,032,435 •	
Total Revenue of the corporation	+ 241		86,257,670 •

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
Whitby Hydro Services Corp	1800227	2008-12-31	+ 243	8,061,977 •	+ 244	19,358,352 •
Whitby Hydro Energy Corporation	1800226	2008-12-31	+ 245	30,432,176 •	+ 246	217,775 •
			+ 247	•	+ 248	•
Aggregate Total Assets 240 + 243 + 245 + 247, etc.			= 249	123,526,588 •		
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.					= 250	105,833,797 •

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 7,657,278 • (If negative, enter zero) X From 30 100.0000 % (Ontario Allocation) X 4 % = 276 306,291 •

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	− 277	•
Subtract: Income Tax	− From 190	1,078,819 •
Net CMT Payable (If negative, enter Nil on Page 17.)	= 280	-772,528 •

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	1,078,819 •
Gross CMT Payable	+ From 276	306,291 •		
Subtract: Foreign Tax Credit for CMT purposes	− From 277	•		
If 276 − 277 is negative, enter NIL in 290	=	306,291 •	− 290	306,291 •
Income Tax eligible for CMT Credit			= 300	772,528 •
B. Income Tax (after deduction of specified credits)			+ From 230	1,078,819 •
Subtract: CMT credit used to reduce income taxes			− 310	•
Income Tax			= 320	1,078,819 •

Transfer to page 17

If A & 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.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

DOLLARS ONLY

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 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	29,494,042
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	14,844,584
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	31,757,783
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
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	339,160
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	878,610
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	77,314,179
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	77,314,179
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	77,314,179

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	334,258
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	334,258

continued on Page 10

Capital Tax *continued from Page 9*

Total Assets (Int.B. 3015R)

			DOLLARS ONLY
Total Assets per balance sheet	+	420	85,032,435
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	85,032,435
Amounts in 360 and 361 (if deducted from assets)	+	440	878,610
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	85,911,045
Investment Allowance (410 ÷ 450) x 390 — Not to exceed 410	=	460	300,810
Taxable Capital 390 – 460	=	470	77,013,369

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	86,257,670
Total Assets (as adjusted)	From 430	85,032,435

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

Amount		Days		Total Days			
7,500,000	x	Days after Dec. 31, 2004 and before Jan. 1, 2006: 36	÷ 73	366	= +	501	
10,000,000	x	Days after Dec. 31, 2005 and before Jan. 1, 2007: 37	÷ 73	366	= +	502	
12,500,000	x	Days after Dec. 31, 2006 and before Jan. 1, 2008: 38	÷ 73	366	= +	504	
15,000,000	x	Days after Dec. 31, 2007: 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

Rate		Days		Total Days			
0.3 %	x	Days before Jan. 1, 2007: 556	÷ 73	366	= +	511	%
0.225 %	x	Days after Dec. 31, 2006 and before Jan. 1, 2009: 557 366	÷ 73	366	= +	512	0.2250 %
Capital Tax Rate 511 + 512					=	516	0.2250 %

continued on Page 11

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

DOLLARS ONLY

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] 100.0000 % Ontario Allocation x From [516] 0.2250 % Capital Tax Rate x Days in taxation year [555] 366 / 366 (366 if leap 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. [X] [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] ______ .

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
			+ [531] .
			+ [532] .
			+ [533] .

Aggregate Taxable Capital [470] + [531] + [532] + [533], etc. - - - - - - - - = [540] .

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] ______ . ÷ From [540] ______ . x From [503] ______ . = [541] ______ .

Transfer to [542] *in Section E below*

Ss.69(2.1) Election Filed

[X] [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] ______ .
− [542] ______ .
= [471] ______ . x From [30] 100.0000 % (Ontario Allocation) x From [516] 0.2250 % (Capital Tax Rate) x [555] 366 (Days in taxation year) * 366 (366 if leap year) = + [523] ______ . **Total Capital Tax for the taxation 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] 77,013,369 . x From [30] 100.0000 % (Ontario Allocation) x From [516] 0.2250 % (Capital Tax Rate) - - - - - - = + [561] 173,280 .

− Capital tax deduction from [995] relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - − From [995] 33,750 .

= [562] 139,530 .

Capital Tax - - - - - - - - [562] 139,530 . x [555] 366 (Days in taxation year) * 366 (366 if leap year) - - - - - = [563] 139,530 . **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] 139,530 .

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - - − [546] .

Capital Tax [543] − [546] *(amount cannot be negative)* - - - - - - - - - = [550] 139,530 .

Transfer to Page 17

continued on Page 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

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 [555] 366 (Days in taxation year) / * 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 [555] 366 (Days in taxation year) / * 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		7,708,231 (Transfer to Page 15)
Add:			
Federal capital cost allowance	+ 601	4,240,137	
Federal cumulative eligible capital deduction	+ 602	58,892	
Ontario taxable capital gain	+ 603	2,380	
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

612 ______ x 5 / 12.5 x	33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ______	÷ 73 (Total Days) 366	= + 633 ______
612 ______ x 5 / 14 x	34 (Days after Dec. 31, 2003) 366	÷ 73 (Total Days) 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	=	4,301,409	640 4,301,409 (Transfer to Page 15)
Deduct:			
Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	4,240,137	
Ontario cumulative eligible capital deduction	+ 651	58,892	
Federal taxable capital gain	+ 652	2,380	
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	4,301,409 (Transfer to Page 15)	

continued on Page 15

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End	CT23 Page 15 of 20
Whitby Hydro Electric Corporation	1800225	2008-12-31	DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1			From ± 600	7,708,231
Total of Additions on page 14			From = 640	4,301,409
Sub Total of deductions on page 14	From = 681	4,301,409		

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 = 4,301,409 ▸ 680 4,301,409

Net income (loss) for Ontario Purposes 600 + 640 − 680 = 690 7,708,231
Transfer to Page 4

DOLLARS ONLY

Continuity of Losses Carried Forward

		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) 22,207	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) 4,760	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 4,760	727	737	747	757
Balance at End of Year		709 (8)	719 17,447	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 1999-12-31	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2000-12-31	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.

(3) Includes 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.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

DOLLARS ONLY

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous 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

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	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						
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
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or	320	1,078,819
Corporate Minimum Tax	+ From	280	
Capital Tax	+ From	550	139,530
Premium Tax	+ From	590	
Total Tax Payable	=	950	1,218,349
Subtract: Payments	−	960	1,490,630
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	-272,281
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	=	975	272,281
Apply to (year month day)		980	*(Includes credit interest)*

* Make 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)*: RAMONA ABI-RASHED

Title: VICE-PRESIDENT OF FINANCE

Full Residence Address: ON L1N 5R8

Signature: Ra[illegible] — Date: Nov. 11/09

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 Other reserves not allowed as deductions for income tax purposes (Attach

Description	Amount	
AMORTIZATION - 2002	3,248,622	00
AMORTIZATION - 2001	853,993	00
AMORTIZATION - 2003	3,229,937	00
AMORTIZATION - 2004	3,483,450	00
AMORTIZATION - 2005	3,658,785	00
AMORTIZATION - 2006	3,896,885	00
AMORTIZATION - 2007	4,128,555	00
AMORTIZATION - 2008	4,401,237	00
CCA - 2003	-3,077,759	00
CCA - 2002	-3,603,102	00
CCA - 2001	-891,488	00
CCA - 2004	-3,143,372	00
CCA - 2005	-3,262,816	00
CCA - 2006	-3,494,000	00
CCA - 2007	-3,840,724	00
ECE - 2002	-90,254	00
ECE - 2001	-23,158	00
ECE - 2003	-83,936	00
ECE - 2004	-78,061	00
ECE - 2005	-72,596	00
ECE - 2006	-68,091	00
ECE - 2007	-63,324	00
ECE - 2008	-58,892	00
CCA - 2008	-4,240,137	00
OM&A COSTS- 2008	-195,277	00
OM&A COSTS- 2007	-75,028	00
SMART METER REVENUE - 2008	131,297	00
SMART METER REVENUE - 2007	125,648	00
SMART METER REVENUE - 2006	82,216	00
Total	878,610	00

Attached Schedule with Total

Loans and advances to unrelated corporations

Title Loans and advances to unrelated corporations

Description	Amount	
AR from unrelated corps o/s over 365 days	258,693	00
Prepaids	75,565	00
Total	334,258	00

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	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: 4,998,141

Subtract (to the extent reflected in net income/loss):

Item		Line	Amount
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):

Item		Line	Amount
Provision for current taxes / cost of current income taxes	+	2111	2,659,137
Provision for deferred income taxes (debits) / cost of future income taxes	+	2112	
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	=		2,659,137 ► + 2116: 2,659,137

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property, occuring before March 22, 2007, for current/prior years

Item	Add line	Amount	Subtract line	Amount
** 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.s.13(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	

Item	Line	Amount
Subtotal (Additions) = ►	+ 2129	
Subtotal (Subtractions) = ►	– 2130	
** Other adjustments	± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131	= 2132	7,657,278
** 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	7,657,278

Deduct:

Item		Line	Amount
* 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: 7,657,278

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)

Page 2 of 3

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

Part 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 that occurred before March 22, 2007 **NOTE (3)** + 2203
- Losses from predecessor corporations on wind-up completed before March 22, 2007 **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 s.57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation that occurred before March 22, 2007, to which fed.s.87 applies and/or a wind-up completed before March 22, 2007, to which fed.s.88(1) applies (see s.57.5(8) and s.57.5(9)). The continuation of CMT losses no longer applies for amalgamations and wind-ups that occur after March 21, 2007.

(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.

(6) Include the lesser of the total investment losses of a predecessor corporation from an investment in another predecessor corporation that is controlled by the first predecessor corporation, and the total unused CMT losses of the other predecessor corporation.

(7) Include the lesser of the total investment losses of the parent corporation from its investment in the subsidiary corporation, and the total unused CMT losses of the subsidiary corporation.

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 1999-12-31	2260	2280
2241	8th preceding taxation year 2000-12-31	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)

Page 3 of 3

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

Part 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 that occurred before March 22, 2007 to which fed.s.87 applies and/or a wind-up completed before March 22, 2007, 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 1999-12-31	2360	2380
2341	8th preceding taxation year 2000-12-31	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
2349	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. (MOR)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

CMT 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	1998-12-31					
9th Prior Year	1999-12-31					
8th Prior Year	2000-12-31					
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
1998-12-31						
1999-12-31						
2000-12-31						
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. (MOR)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

CMT 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
1998-12-31						
1999-12-31						
2000-12-31						
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. (MOR)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-12-31					
9th Prior Year	1999-12-31					
8th Prior Year	2000-12-31					
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
1998-12-31						
1999-12-31						
2000-12-31						
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
1998-12-31						
1999-12-31						
2000-12-31						
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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Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	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)

CURRENT PORTION OF CUSTOMER DEPOSITS	+	754,000
CONSUMER & OTHER DEPOSITS	+	1,146,201
LONG TERM DEBT	+	28,337,942
DUE TO WHITBY HYDRO ENERGY SERVICES CORPORATION	+	373,841
CUSTOMER CREDIT BALANCES	+	1,145,799
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total Transfer to 353 of the CT23	=	31,757,783

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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
Whitby Hydro Electric Corporation	1800225	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
Whitby Hydro Electric Corporation	1800225	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							
						Totals	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	Enerconnect Limited Partnership units			4,760			4,760
2							
						Totals	4,760 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
Whitby Hydro Electric Corporation	1800225	2008-12-31

Part 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								
				Totals				
							Net Loss	G

Note: Properties listed in Part 7 should not be included in any other Part of Schedule 6.

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)		4,760
Add: Amount (if any) of capital gain reserve opening balance from Schedule 13	+	
Capital gain dividend received in the year	+	
Subtotal	=	4,760
Deduct: Amount (if any) of capital gain reserve closing balance from Schedule 13	–	
Gain or Loss (excluding Allowable Business Investment Losses)	=	4,760 H

Determining taxable capital gains

Gain or Loss (excluding Allowable Business Investment Losses)				4,760 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				4,760 I
	Include 100% of the losses in box			*711 of the CT23 or CT8*
Taxable capital gains	4,760 I	x 50 %	=	2,380 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
Whitby Hydro Electric Corporation	1800225	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)
1	43,315,404			0	43,315,404		43,315,404	4	0	0	1,732,616	41,582,788
8	2,207,625	820,864		0	3,028,489	410,432	2,618,057	20	0	0	523,611	2,504,878
10	132,216			0	132,216		132,216	30	0	0	39,665	92,551
12	38,280	82,034		0	120,314	41,017	79,297	100	0	0	79,297	41,017
17	191,309			0	191,309		191,309	8	0	0	15,305	176,004
2	9,188,702			0	9,188,702		9,188,702	6	0	0	551,322	8,637,380
45	122,192			0	122,192		122,192	45	0	0	54,986	67,206
47	11,119,311	6,612,837		0	17,732,148	3,306,419	14,425,729	8	0	0	1,154,058	16,578,090
50		324,643		0	324,643	162,322	162,321	55	0	0	89,277	235,366
95		606,500		0	606,500	303,250	303,250	0	0	0		606,500
Totals	66,315,039	8,446,878			74,761,917	4,223,440	70,538,477				4,240,137	70,521,780

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

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.

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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
Whitby Hydro Electric Corporation	1800225	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)*			= +	841,308 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			=	841,308 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			=	841,308 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**	841,308			
From **N**	– ______			
Current year deduction M minus N	= 841,308 x 7 %	= + 58,892 O		
N + O		= 58,892	▷ –	58,892 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)* = 782,416 Q

See page 2 - Part 2

Ontario Cumulative Eligible Capital Deduction
Schedule 10 Page 2 of 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	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			= _____

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2008 Capital Tax Election of Associated Group Agreement for Allocation of Taxable Capital Deduction (TCD)

CT23 SCHEDULE 591

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Whitby Hydro Electric Corporation	1800225	2008-12-31

The following associated group of corporations includes all the corporations in this associated group (excluding financial institutions and corporations exempt from capital tax) having a permanent establishment in Canada and are hereby making an election under subsection 69(2.1) of the *Corporation Tax Act* to allocate the tax effect of the group's taxable capital deduction (TCD) as calculated in section B1 on page 10 of the CT23 for all taxation years which end in the 2008 calendar year, based on each corporation's total assets and Ontario allocation factor from each corporation's last taxation year ending in the 2007 calendar year.

Applies to taxation years ending in the 2008 calendar year.

Corporation having a permanent establishment in Canada	Last taxation year ending in 2007 calendar year	Ontario Allocation A	Total Assets T	Net Deduction A x TE x (T÷X) ND	Allocation of Net Deduction AND
Corporation Tax Account Number (if applicable) 1800225	YEAR MONTH DAY 2007-12-31	100.0000	81,574,390	22,876	995 33,750
Corporation Name: Whitby Hydro Electric Corporation					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 15,000,000 x **Capital Tax Rate** 516 0.225 = TE 33,750					
Corporation Tax Account Number (if applicable) 1800227	YEAR MONTH DAY 2007-12-31	100.0000	8,344,764	2,340	995
Corporation Name: Whitby Hydro Services Corp					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 15,000,000 x **Capital Tax Rate** 516 0.225 = TE 33,750					
Corporation Tax Account Number (if applicable) 1800226	YEAR MONTH DAY 2007-12-31	100.0000	30,432,176	8,534	995
Corporation Name: Whitby Hydro Energy Corporation					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 15,000,000 x **Capital Tax Rate** 516 0.225 = TE 33,750					
Corporation Tax Account Number (if applicable)	YEAR MONTH DAY				995
Corporation Name					
Tax Effect (TE) of Taxable Capital Deduction From CT23, Page 10, Section B: **TCD** 503 ____ x **Capital Tax Rate** 516 ____ = TE ____					

If insufficient space, attach list.

Total Assets of Associated Group having permanent establishments in Canada X 120,351,330 959

Total Net Deductions of Associated Group having permanent establishments in Canada . . . TND 33,750 994

Total Allocated Net Deductions of Associated Group having permanent establishments in Canada . . . . TAND 33,750

200

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

AMENDED

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 or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 86477 3395 RC0001

Corporation's name
002 Whitby Hydro Electric Corporation

Address of head office
Has this address changed since the last time you filed your T2 return? .... 010 1 Yes [ ] 2 No [X]
(If yes, complete lines 011 to 018)
011 100 Taunton Road East
012 PO Box 59
City: 015 Whitby
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 L1N 5R8

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 [X]
(If yes, complete lines 021 to 028)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? .... 030 1 Yes [ ] 2 No [X]
(If yes, complete lines 031 to 038)
031 100 Taunton Road East
032 PO Box 59
City: 035 Whitby
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 L1N 5R8

040 Type of corporation at the end of the tax year
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ______ YYYY MM DD

To which tax year does this return apply?
Tax year start: 060 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 [X]

If yes, provide the date control was acquired .... 065 ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? .... 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? .... 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? .... 070 1 Yes [ ] 2 No [X]
Amalgamation? .... 071 1 Yes [ ] 2 No [X]
If yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? .... 072 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? .... 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? .... 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used .... 079 ______

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ______

Is the non-resident corporation claiming an exemption under an income tax treaty? .... 082 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] 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.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
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?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	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?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	—
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	—
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	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? (Only complete if yes was entered at line 281)	282		
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	ELECTRICITY DISTRIBN	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 [ ]
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes [ ]	2 No [ ]

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	7,708,231	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	2,380			
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		2,380	►	2,380	B
Subtotal (amount A minus amount B) (if negative, enter "0")				7,705,851	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	7,705,851	
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)				7,705,851	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** 7,705,851 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** 7,705,851 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000 x Number of days in the tax year after 2006 and before 2009 366 / Number of days in the tax year 366 = ... 400,000 1

500,000 x Number of days in the tax year after 2008 ____ / Number of days in the tax year 366 = ... ____ 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** *** 78,933 / 11,250 D = . . . 2,806,507 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 366 / Number of days in the tax year 366 x 17 % = ____ 6

Total of amounts 5 and 6 – 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			7,705,851	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
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		G		
Total of amounts B, C, D, E, F, and G		▶		H
Amount A **minus** amount H (if negative, enter "0")			7,705,851	I

Amount I	7,705,851	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	7,705,851	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 366 / Number of days in the tax year 366	x 8.5 %	=	654,997	K
Amount I	7,705,851	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	7,705,851	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 . . . 654,997 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
Lesser of amounts V and Y (line 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 366 / Number of days in the tax year 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 from Schedule 7	440 ______ x 26 2 / 3 % =		______	A
Foreign non-business income tax credit from line 632		______		
Deduct: Foreign investment income from Schedule 7	445 ______ x 9 1 / 3 % =	______		
	(if negative, enter "0")	______ ▶	______	B
Amount A **minus** amount B (if negative, enter "0")			______	C
Taxable income from line 360		7,705,851		
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 =	______			
	______ ▶	7,705,851		
		x 26 2 / 3 % =	2,054,894	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)		1,502,641		
Deduct: Corporate surtax from line 600		______		
Net amount		1,502,641 ▶	1,502,641	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least		450	______	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		______		
Total Part IV tax payable from Schedule 3		______		
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480	______		
		______ ▶	______	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H		485	______	

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	1,744,000 x 1 / 3	581,333	I
Refundable dividend tax on hand at the end of the tax year from line 485 above		______	J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)		______	

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied by** 38.00 % . . . . **550** 2,928,223 A

Corporate surtax calculation

Base amount from line A above	2,928,223	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	770,585	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		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		
Total of lines 2 to 6			770,585	7
Net amount (line 1 **minus** line 7)			2,157,638	8

Corporate surtax*

Line 8 2,157,638 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			i
Taxable income from line 360	7,705,851		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	7,705,851 ▶	7,705,851	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** ______ D

Subtotal (**add** lines A, B, C, and D) 2,928,223 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	**608**	770,585	
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**	654,997	
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**		
Subtotal		1,425,582 ▶	1,425,582 F

Part I tax payable – Line E **minus** line F . . . . . 1,502,641 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	1,502,641
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		1,502,641

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except 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		1,502,641 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,502,641	
Total credits	890	1,502,641	1,502,641 B

Refund code 894 ____ Overpayment ____

Balance (line A **minus** line B) ____

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . ____

Enclosed payment 898 ____

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ____ Branch number

914 ____ Institution number 918 ____ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . . . 896 1 Yes ☐ 2 No ☒

Certification

I, 950 ABI-RASHED (Last name in block letters) 951 RAMONA (First name in block letters) 954 VICE-PRESIDENT OF FINANCE (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I 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 2009/11/11 Date (yyyy/mm/dd) — [signature] Signature of the authorized signing officer of the corporation — 956 (905) 668-5878 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 RAMONA ABI-RASHED 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 ______

Telephone number ______

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	INSTALMENTS PAID	2,993,271
	TRANSFER TO CT23	-1,490,630
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	1,502,641 A
	Total instalments credited to the taxation year per T9	1,502,641 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	22,825,499	23,068,245
	Total tangible capital assets	2008	+	121,752,763	113,677,245
	Total accumulated amortization of tangible capital assets	2009	–	59,554,996	55,189,437
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	9,169	18,337
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	85,032,435	81,574,390
	Liabilities				
	Total current liabilities	3139	+	10,870,506	11,056,493
	Total long-term liabilities	3450	+	29,823,303	29,433,412
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	40,693,809	40,489,905
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	44,338,626	41,084,485
	Total liabilities and shareholder equity	3640	=	85,032,435	81,574,390
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	14,844,584	11,590,443

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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	+	85,016,298	85,814,212
	Cost of sales	8518	–	63,774,769	63,334,140
	Gross profit/loss	8519	=	21,241,529	22,480,072
	Cost of sales	8518	+	63,774,769	63,334,140
	Total operating expenses	9367	+	14,825,623	15,135,056
	Total expenses (mandatory field)	9368	=	78,600,392	78,469,196
	Total revenue (mandatory field)	8299	+	86,257,670	86,985,971
	Total expenses (mandatory field)	9368	–	78,600,392	78,469,196
	Net non-farming income	9369	=	7,657,278	8,516,775
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	7,657,278	8,516,775
	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	–	2,659,137	3,097,337
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	4,998,141	5,419,438

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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 [X] 2 No [ ]

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [ ] 2 No [X]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes [ ] 2 No [ ]

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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			4,998,141 A
Add:			
Provision for income taxes – current	101	2,659,137	
Interest and penalties on taxes	103	5,521	
Amortization of tangible assets	104	4,401,237	
Loss on disposal of assets	111	8,657	
Taxable capital gains from Schedule 6	113	2,380	
Subtotal of additions		7,076,932 ▶	7,076,932
Other additions:			
Miscellaneous other additions:			
600 Addback re: 12(1)(x)	290	3,238,879	
601 Capital tax booked	291	135,697	
602 Smart Meter Revenues	292	131,297	
604			
Subtotal of other additions	199	3,505,873 ▶	3,505,873
Total additions	500	10,582,805 ▶	10,582,805
Deduct:			
Capital cost allowance from Schedule 8	403	4,240,137	
Cumulative eligible capital deduction from Schedule 10	405	58,892	
Subtotal of deductions		4,299,029 ▶	4,299,029
Other deductions:			
Miscellaneous other deductions:			
700 OM&A capitalized for accounting - SM	390	195,277	
701 CAPITAL TAX PER CT23	391	139,530	
702 Election under s.13(7.4)	392	3,238,879	
704			
Total	394		
Subtotal of other deductions	499	3,573,686 ▶	3,573,686
Total deductions	510	7,872,715 ▶	7,872,715
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			7,708,231

* For reference purposes only

T2 SCH 1 E (08)

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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
Whitby Hydro Electric Corporation	86477 3395 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).
- "1" 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.

		Complete if payer corporation is connected			
Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	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		2			
				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.

			If payer corporation is not connected, leave these columns blank.		
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	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	B	C	D
	Name of connected recipient corporation	Business Number	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD	Taxable dividends paid to connected corporations
	400	410	420	430
1	Town of Whitby			1,744,000
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 1,744,000

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	1,744,000

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)			1,744,000
Other dividends paid in the taxation year (total of 510 to 540)			
Total dividends paid in the taxation year		500	1,744,000
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			1,744,000

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 RC0001	2008-12-31

- This form is used to determine the continuity and use of available losses; to determine the current-year non-capital loss, farm loss, restricted farm loss, and limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that may be applied in a year; and to request a loss carryback to previous years.
- The corporation can choose whether or not to deduct an available loss from income in a tax year. It can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time and no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send it by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes		7,708,231
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter as a positive amount)	2,380	
Taxable dividends deductible under sections 112, 113, or subsection 138(6)		
Amount of Part VI.1 tax deductible		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		2,380
Subtotal (if positive, enter "0")		
Deduct: (increase a loss)		
Section 110.5 and/or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions		
Subtotal		
Add: (decrease a loss)		
Current-year farm loss		
Current-year non-capital loss (if positive, enter "0")		

Continuity of non-capital losses and request for a carryback

	Line		
Non-capital loss at the end of the previous tax year			
Deduct: Non-capital loss expired *	100		
Non-capital losses at the beginning of the tax year	102		
Add: Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105		
Current-year non-capital loss (from calculation above)	110		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Deduct:			
Amount applied against taxable income (enter on line 331 of the T2 return)	130		
Amount applied against taxable dividends subject to Part IV tax	135		
Subtotal			
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
Non-capital losses – Closing balance	180		

* A non-capital loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004.

Election under paragraph 88(1.1)(f)

Paragraph 88(1.1)(f) election indicator	190	Yes ☐

Loss from a wholly owned subsidiary deemed to be a loss of the parent from its immediately previous tax year.

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

	Line	Amount		Total
Capital losses at the end of the previous tax year	200	22,207		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205			22,207
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Add:			Subtotal	22,207
Current-year capital loss (from the calculation on Schedule 6)	210			
Unused non-capital losses that expired in the tax year*			A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			B	
Enter amount from line A or B, whichever is less	215			
ABILs expired as non-capital loss: line 215 divided by the inclusion rate*** 75.0000 %	220			
			Subtotal	22,207

Note: If there has been an amalgamation or a wind-up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total at line 220 above.

	Line		Total
Deduct: Amount applied against the current-year capital gain (see Note 1)	225		4,760
		Subtotal	17,447

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)	Line	Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

	Line	Total
Capital losses – Closing balance	280	17,447

Note 1

Enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2

On lines 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, multiply this amount by the 50% inclusion rate.

* Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004, and before 2006. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line A.

** Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004. Enter the full amount on line B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			
Deduct: Farm loss expired *	300		
Farm losses at the beginning of the tax year	302		
Add: Farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	305		
Current-year farm loss	310		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
Subtotal			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
Farm losses – Closing balance	380		

* A farm loss expires as follows:
- After 10 tax years if it arose in a tax year ending before 2006; or
- After 20 tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business	485		C
Minus the deductible farm loss:			
$2,500 plus D or E, whichever is less		$ 2,500	
(Amount C above ______ – $2,500) divided by 2 = ______ D			
$ 6,250 E			2,500 F
Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410)			

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired *	400		
Restricted farm losses at the beginning of the tax year	402		
Add: Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
Subtotal			
Deduct – Request to carry back restricted farm loss to:			
First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		
Restricted farm losses – Closing balance	480		

Note
The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- After 10 tax years if it arose in a tax year ending before 2006; or
- After 20 tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year				
Deduct: Listed personal property loss expired after seven tax years			500	
Listed personal property losses at the beginning of the tax year			502	
Add: Current-year listed personal property loss (from Schedule 6)			510	
			Subtotal	
Deduct:				
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530			
Other adjustments	550			
			Subtotal	
Deduct – Request to carry back listed personal property loss to:				
First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
Listed personal property losses – Closing balance			580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 - 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from prior tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year. (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 - 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

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SCHEDULE 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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 [X] 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							
		Totals					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	Enerconnect Limited Partnership units		4,760			4,760	
2							
		Totals	4,760			4,760	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							
	Note: Losses are not deductible	Totals					E

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								
	Note: Properties listed in Part 7 should not be included in any other parts of Schedule 6		Totals					G

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)		4,760	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)		4,760	L	
Deduct: Capital gains reserve closing balance (from Schedule 13)	885		M	
Capital gains or losses (amount L minus amount M)	890	4,760		

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses (amount from line 890 above)				4,760	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				4,760	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	4,760 x 50 % =			2,380	U
Enter amount U on line 113 of Schedule 1					

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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
Whitby Hydro Electric Corporation	86477 3395 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	2,380		2,380	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)	2,380	001	002 2,380	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	2,380		022 2,380	C
Total of amounts B and C	2,380		2,380	D
Amount A **minus** amount D (if negative, enter "0")				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				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")		079 L	092 O	

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:
- $400,000 if the corporation's tax year ends in 2007 or 2008;
- $500,000 if the corporation's tax year ends after 2008.

** 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

Partnership 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		7,708,231	P
Deduct: Foreign business income after deducting related expenses*	500		
Taxable capital gains **minus** allowable capital loss – amount A **minus** amount B* (page 1)**	2,380		
Net property income = amount F **minus** amount G, H, and N* (page 1)	Q		
Personal services business income after deducting related expenses*	520		
	2,380 ▶	2,380	
Net amount		7,705,851	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")		7,705,851	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
Whitby Hydro Electric Corporation	86477 3395 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 (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (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	1	BLDG, PLANT & DISTR	43,315,404			0		43,315,404	4	0	0	1,732,616	41,582,788
2	8	OFFICE EQUIPMENT	2,207,625	820,864		0	410,432	2,618,057	20	0	0	523,611	2,504,878
3	10	COMPUTER EQUIPMENT	132,216			0		132,216	30	0	0	39,665	92,551
4	12	COMPUTER SOFTWARE	38,280	82,034		0	41,017	79,297	100	0	0	79,297	41,017
5	17	YARD IMPROVEMENTS	191,309			0		191,309	8	0	0	15,305	176,004
6	2	GEN & DISTR < 1988	9,188,702			0		9,188,702	6	0	0	551,322	8,637,380
7	45	COMPUTER EQUIPMENT ACQUIF	122,192			0		122,192	45	0	0	54,986	67,206
8	47		11,119,311	6,612,837		0	3,306,419	14,425,729	8	0	0	1,154,058	16,578,090
9	50	Computer Equipment		324,643		0	162,322	162,321	55	0	0	89,277	235,366
10	95			606,500		0	303,250	303,250	0	0	0		606,500
		Total	66,315,039	8,446,878			4,223,440	70,538,477				4,240,137	70,521,780

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** 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.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		8,446,878		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Amortization of deferred charges included in depreciation	+			
Total additions per books	=	8,446,878	►	8,446,878
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Smart meter assets not capitalized for accounting purposes	+	336,195		
Total proceeds per books	=	336,195	– ►	336,195
Depreciation and amortization per accounts – Schedule 1			–	4,392,068
Loss on disposal of fixed assets per accounts			–	8,657
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	3,709,958

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		61,941,010
Opening net book value	–	58,231,050
Net change per financial statements	=	3,709,960

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Tax return – Other – Amount

Title Tax return – Other – Amount

Description	Amount	
Base station - Class 8 (not capitalized for accounting purposes)	302,400	00
Substation equipment - Class 8 (not capitalized for accounting purposes)	9,765	00
Harris software - Class 50 (not capitalized for accounting purposes)	24,030	00
Total	336,195	00

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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.	Whitby Hydro Services Corp		86477 5598 RC0001	3					
2.	Whitby Hydro Energy Corporation		86477 3999 RC0001	1					

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

Whitby Hydro Electric Corp PILS return 081231 - amended for 2009-09-24 09:37 | 2008-12-31 | Whitby Hydro Electric Corporation 86477 3395 RC0001

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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") 200 841,308 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) 230 841,308 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) 841,308 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 841,308

less amount from line 249 ______

Current year deduction 841,308 x 7.00 % = 250 58,892 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 58,892 ► 58,892 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") 300 782,416 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.

T2 SCH 10 (04)

Canada

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4			
Line 3 minus line 4 (if negative, enter "0")			▶		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	409		▶		9	
Line 6 minus line 9 (if negative, enter "0")					▶	O
Line N minus line O (if negative, enter "0")						P
Line 5			× 1 / 2 =			Q
Line P minus line Q (if negative, enter "0")						R
Amount R			× 2 / 3 =			S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					410	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . . 050 Year 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 [X]

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400	
1	Whitby Hydro Electric Corporation	86477 3395 RC0001	1	400,000	100.0000	400,000	
2	Whitby Hydro Services Corp	86477 5598 RC0001	1	400,000			
3	Whitby Hydro Energy Corporation	86477 3999 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. If the tax year straddles January 1, 2007, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $400,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (08)

Canada

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	WHITBY HYDRO ENERGY CORP	86477 3999 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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
5. Corporations that become a CCPC or a DIC . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	12,965,466	A
Taxable income for the year (DICs enter "0")*	110	7,705,851	B		
Income for the credit union deduction* (amount E in Part 3 of Schedule 17) 120					
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less* 130					
Subtotal (add lines 120 and 130) ►			C		
For a CCPC, aggregate investment income (line 440 of the T2 return)*		D			
Line B **minus** line C (if negative enter "0")	7,705,851	E			
Amount from line D or E, whichever is less	140		F		
Income taxable at the general corporate rate (line B **minus** lines C and F)	150	7,705,851			
After-tax income (line 150 **multiplied by** 68 %)			190	5,239,979	G
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) ►					H
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		I
Subtotal (**add** lines A, G, H, and I)				18,205,445	J
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) ►					K
GRIP before adjustment for specified future tax consequences (line J **minus** line K) (amount can be negative)			490	18,205,445	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560		
GRIP at the end of the tax year (line 490 **minus** line 560) Enter this amount on line 160 on Schedule 55.			590	18,205,445	

* **Note:** For lines 110, 120, 130 and D, 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 or leave it blank.

First previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year			8,750,733	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	400,000	L1			
Aggregate investment income (line 440 of the T2 return)		M1			
Subtotal (**add** lines K1, L1, and M1)	400,000	►	400,000	N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")			8,350,733 ►	8,350,733	O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R1

Aggregate investment income (line 440 of the T2 return) . . . . ____ S1

Subtotal (add lines Q1, R1, and S1) ____ ► ____ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ____ ► ____ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ____ V1

GRIP adjustment for specified future tax consequences to first previous tax year (line V1 **multiplied by** 68 %) . . . **500** ____

Second previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year 6,958,549 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** . . . . . . ____

Subtotal (**add** lines K2, L2, and M2) 300,000 ► 300,000 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 6,658,549 ► 6,658,549 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R2

Aggregate investment income (line 440 of the T2 return) . . . . ____ S2

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . . ____

Subtotal (**add** lines Q2, R2, and S2) ____ ► ____ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ____ ► ____ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ____ V2

GRIP adjustment for specified future tax consequences to second previous tax year (line V2 **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 the current tax year 4,379,611 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** . . . . . . ______

Subtotal (add lines K3, L3, and M3) ______ ► ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 4,379,611 ► 4,379,611 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . . ______

Subtotal (add lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to third previous tax year (line V3 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") . . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or 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

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ________ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ________ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

- Non-capital losses . . . . ________
- Net capital losses . . . . ________
- Farm losses . . . . ________
- Restricted farm losses . . . . ________
- Limited partnership losses . . . . ________

Subtotal ________ ▶ ________ HH

Subtotal (**add** lines FF, GG, and HH) ________ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ________ JJ

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ________ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ________ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ________ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ________ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ________ ▶ ________ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or 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.

Whitby Hydro Electric Corp PILS return 081231 - amended for 2009-09-24 09:37 | 2008-12-31 | Whitby Hydro Electric Corporation 86477 3395 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Whitby Hydro Electric Corporation	86477 3395 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		1,744,000			
Total taxable dividends paid in the tax year	100	1,744,000			
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	18,205,445	
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.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2009-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address:**

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2009-01-31	226,750			226,750
2009-02-28	226,750			226,750
2009-03-31	226,750			226,750
2009-04-30	226,750			226,750
2009-05-31	226,750			226,750
2009-06-30	226,750			226,750
2009-07-31	226,750			226,750
2009-08-31	226,750			226,750
2009-09-30	226,750			226,750
2009-10-31	226,750			226,750
2009-11-30	226,750			226,750
2009-12-31	226,740			226,740
Total	2,720,990			2,720,990

Corporate Taxpayer Summary

Corporate information

Corporation's name: Whitby Hydro Electric Corporation
Taxation Year: 2008-01-01 to 2008-12-31
Jurisdiction: Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	☒	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated: Y
Corporation is related: Y
Number of associated corporations: 2
Type of corporation: Canadian-Controlled Private Corporation
Total amount due (refund) federal and provincial*: -272,281

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	7,708,231
Taxable income	7,705,851
Donations	
Calculation of income from an active business carried on in Canada	7,705,851
Dividends paid	1,744,000
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	12,965,466
Balance of the general rate income pool at the end of the year	18,205,445
Part I tax (base amount)	2,928,223
Surtax	

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	1,502,641	ITC refund	
M&P deduction		Part I.3		Dividends refund	
Foreign tax credit		Part IV		Instalments	1,502,641
Political contributions		Part III.1		Surtax credit	
Investment tax credits		Other*		Other*	
Abatement/Other*	1,425,582	Provincial or territorial tax			
				Balance due/refund (–)	

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	

Summary of federal carryforward/carryback information (continued)

Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	
Investment tax credits	
Non-capital losses	
Capital/L.P.P. losses	17,447
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	106,004
Capital dividend amount	
Part I tax credit (Schedule 42)	
Cumulative eligible capital	782,416
Capital gains reserves	
Financial statement reserve	
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario (CT-23)	Québec (CO-17)	Alberta (AT1)
Net income	7,708,231		
Taxable income	7,705,851		
% Allocation	100.00		
Attributed taxable income	7,705,851		
Surtax	42,500	N/A	N/A
Tax payable before deduction*	1,078,819		
Deductions and credits	42,500		
Net tax payable	1,078,819		
Attributed taxable capital	77,013,369		N/A
Capital tax payable**	139,530		N/A
Total tax payable***	1,218,349		
Instalments and refundable credits	1,490,630		
Balance due/Refund (-)	-272,281		

* For Québec, this includes special taxes.
** For Québec, this includes compensation tax and registration fee.
*** For Ontario, this includes corporate minimum tax and premium tax.

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable**			
Instalments and refundable credits			
Balance due/Refund (-)			

* For British Columbia, this includes the Logging Tax Payable.
** For Manitoba, this includes the Outstanding Balance Excluding Instalments.

Summary of provincial information – provincial income tax payable (continued)

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Ontario	Québec	Alberta
Non-capital losses			
Net capital/L.P.P. losses	17,447		
Farm losses			
Restricted farm losses			
Donations			
Capital gains reserves			
Financial statement reserves			
Other reserves			
Eligible capital	782,416	782,416	782,416

Other carryforward amounts

Ontario	
Continuity of other eligible CMT losses – Filling Corporation – OCMT101	
Predecessor corporations only – Amalgamation – OCMT101	
Predecessor corporations only – Wind-up – OCMT101	
CMT credit carryovers workchart – Filling Corporation – OCMT101	
CMT credit carryovers workchart – Predecessor corporations only – Amalgamation	
CMT credit carryovers workchart – Wind-up – OCMT101	
Ontario current taxation year closing balance in pool of deductible SR&ED expenditures – O161	
Continuity Schedule for Federal ITC relating to SR&ED Expenditures for the Preceding Taxation Year – O161	
Continuity Schedule for the Amount of Federal ITC from SR&ED Expenditures relating to QORD for the Preceding Taxation Year – O161	
Québec	
R&D expenditures not deducted at the end of the year – RD-222	
Tax credit for fees and dues paid to a research consortium – RD-1029.8.9.03	
Foreign non-business income tax credits – CO-17S.39	
Non-refundable tax credit for resources – 1029.8.36.EM	
Investment Tax Credit – CO-1029.8.36.IN	
Development work expenses – FM220.3	
Excess development work expenses – FM220.3	
Balance of patronage dividends – CO-786	
Alberta	
Unclaimed SR&ED expenditure pool deduction balance – A16	
British Columbia	
Scientific research and experimental development – Schedule 425	
Manufacturing and processing – Schedule 426	
Manitoba	
Research and development – Schedule 380	
Manufacturing investment – Schedule 381	
Co-op education and apprenticeship – Schedule 384	
Odour control – Schedule 385	
Community enterprise investment – Schedule 387	
Saskatchewan	
Royalty tax rebate – Schedule 400	
Manufacturing and processing investment – Schedule 402	
Research and development – Schedule 403	
Newfoundland and Labrador	
Direct equity tax – Schedule 303	
Prince Edward Island	
Investment – Schedule 321	
Nova Scotia	
Energy efficiency tax credit – Schedule 342	
Manufacturing and processing investment – Schedule 344	
New Brunswick	
Research and development – Schedule 360	
Nunavut	
Investment – Schedule 480	

EXHIBIT 5

COST OF CAPITAL AND CAPITAL STRUCTURE

OVERVIEW

Whitby Hydro was incorporated November 1, 2000 in accordance with the requirements of the Electricity Act, 1998, S.O. 1998, Schedule A.

Whitby Hydro is wholly owned subsidiary of Whitby Hydro Energy Corporation, which in turn is wholly owned by the Corporation of the Town of Whitby.

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2010 Test year.

CAPITAL STRUCTURE

Whitby Hydro currently has a current deemed capital structure of 56.7% debt and 43.3% equity with a combined return on capital of 8.01% based on a debt rate of 7.25% and an equity return of 9% as approved by the Board in the 2009 IRM rate decision EB-2008-0251 and in the 2006 EDR Decision.

For the purposes of preparing its 2010 rebasing application, Whitby Hydro used the previous Board approved cost of capital parameters and the deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the “Cost of Capital Report” EB-2006-088 and EB-2006-0089).

Table 5-1 details Whitby Hydro’s deemed capital structure for 2010. Whitby Hydro’s capital value structure has grown by $16.0M from 2006 Board Approved to the 2010 Test year due to the expansion in rate base. Capital Expenditures have consistently been greater than depreciation expense since 2004.

Table 5-1 - Capitalization and Cost of Capital (Appendix 2-O)

Particulars	Capitalization Ratio		Cost Rate	Return
	2010 Test Year			
	(%)	($)	(%)	($)
Debt				
Long-Term Debt	56.00%	$42,447,685	7.62%	$3,234,514
Short-Term Debt	4.00%	$3,031,977	1.33%	$40,325
Total Debt	60.00%	$45,479,662	7.20%	$3,274,839
Equity				
Common Equity	40.00%	$30,319,775	8.01%	$2,428,614
Preferred Shares				
Total Equity	40.00%	$30,319,775	8.01%	$2,428,614
Total	100.00%	$75,799,437	7.52%	$5,703,453

Table 5-2 outlines the 2006 Board Approved capital structure as compared to actual results for 2006 through 2008.

Whitby Hydro has 3 promissory notes with the Town of Whitby, its municipal shareholder, totaling $28,337,942 as shown below. Whitby Hydro has no other long term or short-term debt as of the time of filing. The promissory notes were issued November 1, 2000. Copies of the promissory notes are included as Attachment 5-1.

Promissory Notes -Town of Whitby

	Principal Amount	Interest Rate	Annual Interest payment	Term
Note 1	$1,460,300	7.25%	$105,872	Sixty days written notice
Note 2	$5,061,000	7.25%	$366,923	Sixty days written notice
Note 3	$21,816,642	7.00%	$1,527,205	Twelve months written notice
	$28,337,942	7.06%	$2,000,000	

Whitby Hydro does not have any preferred shares and does not plan to buy back any common shares. Share capital for Whitby Hydro consists of 165 common shares issued to Whitby Hydro Energy Corporation.

Changes in the capital structure from 2006 through to 2008 are due to increases in the equity component while the debt amount has remained unchanged. Equity has grown as a result of the accumulation of yearly net income with dividends remaining well below net income since 2004.

Table 5-2 - Capital Structure - Analysis of Actual vs. 2006 Board Approved

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual
Amounts - $				
Long Term Debt	30,302,709	28,337,942	28,337,942	28,337,942
Common Equity	30,302,709	39,731,505	39,166,203	38,735,015
	60,605,418	68,069,447	67,504,145	67,072,957
Ratios -%				
Long Term Debt	50.00	41.63	41.98	42.25
Equity	50.00	58.37	58.02	57.75
	100.00	100.00	100.00	100.00
Interest on Long Term Debt	2,196,946	2,000,000	2,000,000	2,000,000
Net Income	2,727,244	2,155,137	854,698	1,312,812
Long Term Debt Rate	7.25%	7.06%	7.06%	7.06%
Return on Equity	9.00%	5.42%	2.18%	3.39%
Deemed Long Term Debt Rate-%	7.25%	7.25%	7.25%	7.25%
Deemed Rate of Return-%	9.00%	9.00%	9.00%	9.00%
Actual Cost of Capital		6.10%	4.23%	4.94%
Deemed Cost of Capital	8.13%	8.13%	8.13%	8.07%
Deemed Capital Structure -Ratios %				
Long Term Debt	50.00	50.00	50.00	53.30
Equity	50.00	50.00	50.00	46.70
	100.00	100.00	100.00	100.00

COST OF CAPITAL

COST OF DEBT: LONG TERM

Since the promissory notes are with an affiliate and are callable, Whitby Hydro is requesting a return on Long Term Debt for the 2010 Test Year of 7.62% in accordance with the Cost of Capital Report. Whitby Hydro understands, the debt rate of 7.62% reflects the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on February 24, 2009 and that the OEB will be finalizing an equivalent debt rate for 2010 rates based on January 2010 market interest rate information. Whitby Hydro also understands that the OEB's updated long term debt rate would be applied to the deemed long term debt component for the purpose of calculating the 2010 revenue requirement.

COST OF DEBT: SHORT TERM

Whitby Hydro is requesting a return on Short Term Debt for the 2010 Test year of 1.33% in accordance with the Cost of Capital Parameters Updates for 2009 Cost of Service Applications issued by the OEB on February 24th, 2009. Whitby Hydro understands that the OEB will be finalizing the return on short term debt for 2010 rates based on January 2010 market interest rate information.

RETURN ON EQUITY

Whitby Hydro is requesting a return on equity ("ROE") for the 2010 Test year of 8.01% in accordance with the Cost of Capital Parameters Updates for 2009 Cost of Service Applications issued by the OEB on February 24th, 2009. Whitby Hydro understands that the OEB will be finalizing the return on short term debt for 2010 rates based on January 2010 market interest rate information.

Details of Whitby Hydro's Cost of Capital and Return on Equity are presented in Table 5-2. Whitby Hydro's ROE in 2006 (5.42%), 2007 (2.18%) and 2008 (3.19%) were well below the deemed ROE of 9%.

Attachment 5-1: Promissory Notes

PROMISSORY NOTE #1

In consideration of the transfer of assets by the municipal Corporation of the Town of Whitby (the "Town") to Whitby Hydro Electric Corporation ("Wiresco") pursuant to Town By-law 4703-00, Wiresco acknowledges itself indebted and hereby promises to pay the Town, or its assigns, at its offices at 575 Rossland Road East, Whitby, Ontario, L1N 2M8 (or such other place as the Town may direct Wiresco in writing) the principal sum of $1,460,300.00, in lawful money of Canada, together with interest thereon of 7.25% per annum. The interest payable for each year the note is in effect will be $105,872.00 commencing in 2001.

Upon the written request by Wiresco to the Town, the interest rate and the terms upon which interest is payable may be subject to re-negotiation from time to time, as a result of regulatory changes. Any amendment to the interest rate or the terms upon which interest is payable shall be mutually agreed to by the town and Wiresco in writing.

The Town has the option of calling for the repayment of the principal amount in whole or part, with sixty days written notice. The schedule of interest payments would change in the event of principal repayment. Any written notice or communication to be given or delivered by the Town shall be deemed to be duly given and delivered to Wiresco when delivered by hand or sent via facsimile to the following address:

Whitby Hydro Electric Corporation
Box 59, 100 Taunton Road East
Whitby, Ontario
L1N 5R8
Attention: President
Facsimile No.: (905) 668-8791

Wiresco shall have the option of prepaying the principal amount thereof at any time, in whole or in part, with the prior written consent of the Town.

This Note shall be binding upon Wiresco and its successors and assigns. This Note may be assigned by Wiresco with the prior written consent of the Town.

In the event of the consolidation, amalgamation or merger of Wiresco with any other corporation or the sale of a majority of issued and outstanding shares in the capital of Wiresco, the balance of principal with accrued interest on this note shall become due and payable on closing of any consolidation, amalgamation, merger or transfer of the majority of issued and outstanding shares in the capital of Wiresco.

This Note shall be governed by and construed in accordance with the laws of the Province of Ontario.

Dated the 1st day of November, 2000

WHITBY HYDRO ELECTRIC CORPORATION

Per: _______________

Per: _______________

CORPORATION OF THE TOWN OF WHITBY

Per: _______________

Per: _______________

PROMISSORY NOTE #2

In consideration of the transfer of assets by the municipal Corporation of the Town of Whitby (the "Town") to Whitby Hydro Electric Corporation ("Wiresco") pursuant to Town By-law 4703-00, Wiresco acknowledges itself indebted and hereby promises to pay the Town, or its assigns, at its offices at 575 Rossland Road East, Whitby, Ontario, L1N 2M8 (or such other place as the Town may direct Wiresco in writing) the principal sum of $5,061,000.00, in lawful money of Canada, together with interest thereon of 7.25% per annum. The interest payable for each year the note is in effect will be $366,923.00 commencing in 2001.

Upon the written request by Wiresco to the Town, the interest rate and the terms upon which interest is payable may be subject to re-negotiation from time to time, as a result of regulatory changes. Any amendment to the interest rate or the terms upon which interest is payable shall be mutually agreed to by the Town and Wiresco in writing.

The Town has the option of calling for the repayment of the principal amount in whole or part, with sixty days' written notice. The schedule of interest payments would change in the event of principal repayment. Any written notice or communication to be given or delivered by the Town shall be deemed to be duly given and delivered to Wiresco when delivered by hand or sent via facsimile to the following address:

Whitby Hydro Electric Corporation
Box 59,100 Taunton Road East
Whitby, Ontario
L1N 5R8
Attention: President
Facsimile No.: (905) 668-8791

Wiresco shall have the option of prepaying the principal amount thereof at any time, in whole or in part, with the prior written consent of the Town.

This Note shall be binding upon Wiresco and its successors and assigns. This Note may be assigned by Wiresco with the prior written consent of the Town.

In the event of the consolidation, amalgamation or merger of Wiresco with any other corporation or the sale of a majority of issued and outstanding shares in the capital of Wiresco, the balance of principal with accrued interest on this note shall become due and payable on closing of any consolidation, amalgamation, merger or transfer of the majority of issued and outstanding shares in the capital of Wiresco.

This Note shall be governed by and construed in accordance with the laws of the Province of Ontario.

Dated the 1st day of November, 2000

WHITBY HYDRO ELECTRIC CORPORATION

Per: ______________________

Per: ______________________

CORPORATION OF THE TOWN OF WHITBY

Per: ______________________

Per: ______________________

PROMISSORY NOTE #3

In consideration of the transfer of assets by the municipal Corporation of the Town of Whitby (the "Town") to Whitby Hydro Electric Corporation ("Wiresco") pursuant to Town By-law 4703-00, Wiresco acknowledges itself indebted and hereby promises to pay the Town, or its assigns, at its offices at 575 Rossland Road East, Whitby, Ontario, L1N 2M8, (or such other place as the Town may direct Wiresco in writing) the principal sum of $21,816,642.00 in lawful money of Canada, together with interest thereon as hereafter provided. The interest payable in any given year shall be based on the following payment schedule:

		Interest Rate/Annum	
2001	$ 565,660.00	2.59%	½ payable June 1st, ½ payable December1st
2002	$1,527,205.00	7.00%	½ payable June 1st, ½ payable December1st
2003	$2,027,205.00	9.29%	½ payable June 1st, ½ payable December1st
2004	$2,027,205.00	9.29%	½ payable June 1st, ½ payable December1st
2005	$1,527,205.00	7.00%	½ payable June 1st, ½ payable December1st
2006	$1,527,205.00	7.00%	½ payable June 1st, ½ payable December1st
2007	$1,527,205.00	7.00%	½ payable June 1st, ½ payable December1st and each year thereafter.

Upon the written request by Wiresco to the Town, the interest rate and the terms upon which interest is payable may be subject to re-negotiation from time to time, as a result of regulatory changes. Any amendment to the interest rate or the terms upon which interest is payable shall be mutually agreed to by the Town and Wiresco in writing.

The Town has the option of calling for the principal amount in whole or part, with 12 months' written notice. The schedule of interest payments would change in the event of principal repayment. Any written notice or communication to be given or delivered by the Town shall be deemed to be duly given and delivered to Wiresco when delivered by hand or sent via facsimile to the following address:

Whitby Hydro Electric Corporation
Box 59, 100 Taunton Road East
Whitby, Ontario
L1N 5R8
Attention: President
Facsimile No.: (905) 668-8791

Wiresco shall have the option of prepaying the principal amount thereof at any time, in whole or in part, with the prior written consent of the Town.

This Note shall be binding upon Wiresco and its successors and assigns. This Note may be assigned by Wiresco with the prior written consent of the Town.

In the event of the consolidation, amalgamation or merger of Wiresco with any other corporation or the sale of a majority of issued and outstanding shares in the capital of Wiresco, the balance of principal with accrued interest on this note shall become due and payable on closing of any consolidation, amalgamation, merger or transfer of the majority of issued and outstanding shares in the capital of Wiresco.

This Note shall be governed by and construed in accordance with the laws of the Province of Ontario.

Dated the 1st day of November, 2000

WHITBY HYDRO ELECTRIC CORPORATION

Per: ______________________

Per: J. E. Favelle

CORPORATION OF THE TOWN OF WHITBY

Per: ______________________

Per: ______________________

EXHIBIT 6
REVENUE DEFICIENCY OR SURPLUS

REVENUE REQUIREMENT

Whitby Hydro has calculated its 2010 Service Revenue Requirement based on a cost of service rate application using a forward test year and forecast information for distribution expenses, amortization expenses, deemed interest expense and deemed return on capital and a proxy for PILs.

Whitby Hydro collects its service revenue requirement primarily through distribution rates. Other Revenue is collected through specific service charges, late payment charges, other distribution revenue and other income/expense. Other Revenues are treated as offsets against the service revenue requirement to arrive at a base revenue requirement. Details of other revenue are addressed in Exhibit 3.

For 2010, Whitby Hydro's proposed service revenue requirement has been calculated as $20,747,189. Total revenue offsets have been calculated as $890,743. The resulting base revenue requirement is $19,856,446.

Table 6-1 summarizes Whitby Hydro's revenue requirement.

Table 6-1: Revenue Requirement

	2010 Proposed
OM&A Expenses	$8,919,421
Amortization/Depreciation	$4,929,391
Capital Taxes	$45,600
Income Taxes (Grossed up)	$1,149,325
Return	
Deemed Interest Expense	$3,274,839
Return on Deemed Equity	$2,428,614
Service Revenue Requirement	$20,747,189
Other revenue (offset)	$890,743
Base Revenue Requirement	$19,856,446

DETERMINATION OF NET UTILITY INCOME

Whitby Hydro has calculated its 2010 utility income before deemed interest expenses to be $6,852,777. After interest and taxes the utility net income is $2,428,614. Details are provided in Table 6-2.

Table 6-2: 2010 Utility Income

	2010 Utility Income
Operating Revenues:	
Distribution Revenue (at Proposed Rates)	$19,856,446
Other Revenue **(1)**	$890,743
Total Operating Revenues	$20,747,189
Operating Expenses:	
OM+A Expenses	$8,919,421
Depreciation/Amortization	$4,929,391
Capital taxes	$45,600
Subtotal	$13,894,412
Deemed Interest Expense	$3,274,839
Total Expenses	$17,169,251
Utility income before income taxes	$3,577,938
Income taxes (grossed-up)	$1,149,325
Utility net income	$2,428,614

(1)

Other Revenues / Revenue Offsets	
Specific Service Charges	$157,835
Late Payment Charges	$321,000
Other Distribution Revenue	$333,909
Other Income and Deductions	$78,000
Total Revenue Offsets	$890,743

RATE BASE:

Whitby Hydro has determined its rate base for 2010 as $75,799,437. A breakdown has been included as table 6-3. The requested return on rate base represents a 7.52% weighted average cost of capital. Details of the cost of capital are provided in Exhibit 5.

Table 6-3: Breakdown of Rate Base

Particulars		2010 Rate Base Application
Gross Fixed Assets (average)	**(3)**	$130,674,768
Accumulated Depreciation (average)	**(3)**	($66,557,712)
Net Fixed Assets (average)	**(3)**	$64,117,057
Allowance for Working Capital	**(1)**	$11,682,381
Total Rate Base		$75,799,437

(1) Allowance for Working Capital - Derivation		
Controllable Expenses		$8,919,421
Cost of Power		$68,963,116
Working Capital Base		$77,882,537
Working Capital Rate %	**(2)**	15.00%
Working Capital Allowance		$11,682,381

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 DEFICIENCY:

The revenue deficiency in the 2010 test year is the difference between the revenue that Whitby Hydro would earn in the test year using current rates and the revenue forecast calculated from the 2010 base revenue requirement.

Whitby Hydro has provided detailed calculations supporting its 2010 revenue deficiency. Whitby Hydro's net revenue deficiency is $1,386,163 (or $2,008,932 when grossed up for PILs). Details of the calculation can be found in Table 6-4.

The revenue deficiency has been calculated net of electricity price differentials which are captured in the variance accounts (RSVAs) and are also net of any costs associated with low voltage (LV) charges or smart meter expenditures/revenues. There are no amounts included for regulatory asset recoveries or LRAM claims.

1 **Table 6-4: Calculation of Revenue Deficiency**

Particulars	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		$2,008,932
Distribution Revenue	$17,847,514	$17,847,514
Other Operating Revenue Offsets - net	$890,743	$890,743
Total Revenue	$18,738,257	$20,747,189
Operating Expenses	$13,894,412	$13,894,412
Deemed Interest Expense	$3,274,839	$3,274,839
Total Cost and Expenses	$17,169,251	$17,169,251
Utility Income Before Income Taxes	$1,569,006	$3,577,938
Tax Adjustments to Accounting Income per 2009 PILs	$129,559	$129,559
Taxable Income	$1,698,565	$3,707,497
Income Tax Rate	31.00%	31.00%
Income Tax on Taxable Income	$526,555	$1,149,324
Income Tax Credits	$ -	$ -
Utility Net Income	$1,042,451	$2,428,614
Utility Rate Base	$75,799,437	$75,799,437
Deemed Equity Portion of Rate Base	$30,319,775	$30,319,775
Income/Equity Rate Base (%)	3.44%	8.01%
Target Return - Equity on Rate Base	8.01%	8.01%
Sufficiency/Deficiency in Return on Equity	-4.57%	0.00%
Indicated Rate of Return	5.70%	7.52%
Requested Rate of Return on Rate Base	7.52%	7.52%
Sufficiency/Deficiency in Rate of Return	-1.83%	0.00%
Target Return on Equity	$2,428,614	$2,428,614
Revenue Sufficiency/Deficiency	$1,386,163	($0)
Gross Revenue Sufficiency/Deficiency	$2,008,932 **(1)**	

DRIVERS OF REVENUE DEFICIENCY

A list of the key drivers of the revenue deficiency has been summarized in table 6-5 below:

Table 6-5: Drivers of Revenue Deficiency ($K)

Amount		Driver
$	(1,718)	Increase in OM&A Expenses
$	(1,432)	Increase in Amortization
$	(779)	Increase in Return on Rate Base
$	680	Decrease in PILs
$	**(3,250)**	**Total Change in Service Revenue Requirement**
$	4	Decrease in Revenue Offsets
$	1,237	Load Growth
$	**(2,009)**	**Total Revenue Deficiency**

Generally, the drivers can be grouped into those that support the total change in the service revenue requirement and other underlying influences such as load changes and difference in revenue offsets. To quantify the revenue deficiency, the changes between the 2006 Board approved levels and the 2010 test year forecast have been calculated for the various drivers.

Whitby Hydro's revenue deficiency is a result of:

- An increase in OM&A Expenses of $1,718K from 2006 EDR. Explanations for these increases have been addressed in Exhibit 4.
- Increases in amortization of $1,432K which is a result of the additions to rate base between the 2006 EDR and 2010 proposed.
- The increase in the return on rate base which is influenced by two underlying factors:
  i. the change in rate base and
  ii. the change to the rate of return.

  A breakdown is as follows:

Breakdown of Increase in Return on Rate Base:

Increase in Rate Base:		*Decrease in Rate of Return:*	
2010 Rate Base	75,799	2010 Rate of Return	7.52%
2006 EDR Rate Base	60,605	2006 EDR Rate of Return	8.13%
Difference	15,194	Difference	-0.61%
2010 Rate of Return	7.52%	2006 EDR Rate Base	60,605
Impact	1,143	Impact	(370)

Total Increase in Return on Rate Base: $1,143 - $370+$6 (rounding) = $779K

- A decrease in the proxy for PILs of $680K which is largely due to changes in tax rates (-$498k) and changes in taxable income (-$182K).
- Small changes in the Revenue Offset (see Exhibit 3 for details).
- An increase in load growth which represents $1,237K. Whitby Hydro has experienced significant customer growth when compared to the loads included in the 2006 EDR. This has helped to offset the level of revenue deficiency which was driven by the changes to the service revenue requirement.

EXHIBIT 7
COST ALLOCATION

COST ALLOCATION

INTRODUCTION

On September 15, 2006, the Ontario Energy Board (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 the User Instructions (the Instructions) for the Model. Whitby Hydro prepared a cost allocation informational filing consistent with its best understanding of the OEB Directions, Guidelines, Model and Instructions. Whitby Hydro submitted this filing to the OEB on February 28, 2007.

The results of the cost allocation study are generally viewed in the form of revenue to cost ratios. The ratios are the percentages of distribution revenue collected from each customer class compared to the costs allocated to each class. The percentages identify the customer classes that are being subsidized and those that are over-contributing, based on the cost allocation study. A percentage of less than 100% means that the customer class is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates that the customer class is over-contributing and is subsidizing other classes of customers. Since the allocation of costs to customer classes is an inherently imprecise exercise, revenue to cost ratios that vary from 100% but are within the Board-approved target ranges are considered to recover costs equitably.

One of the main objectives of the informational filing was to provide comparison data on any apparent cross-subsidization among a distributor's customer classes. It was intended to be an informational filing only but would give the distributor an indication of potential cross-subsidization from one class to another and serve as a useful tool in the future.

As part of the Filing Requirements for 2010 Cost of Service applications set out in Chapter 2 of the May 27, 2009 update to the document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements"), the Board directed distributors to file a completed Cost Allocation study using the Board's approved methodology. In light of this and other related filing requirements, Whitby Hydro retained Elenchus Research Associates (ERA) to perform the following services:

- Revise the Initial Cost Allocation model for the transformer ownership allowance correction as specified by the Board.
- Review the Initial Cost Allocation model and update it for identified model corrections.

- Provide recommendations for a 2010 Cost Allocation study and complete the study using 2010 test year data and the best information available.

A copy of ERA's report has been included as Attachment 7-5.

SUMMARY OF RESULTS AND PROPOSED CHANGES:

Cost Allocation Study Results

Whitby Hydro has completed its Cost Allocation Study according to the Filing Requirements and includes the three sets of revenue to cost ratios requested by the Board.

The following Tables have been submitted based on Appendix 2-P of the Filing Requirements:

Table 7-1: Revenue to Cost Ratios – Appendix 2-P(a)

Customer Class	(1) From Cost Allocation Model	(2) Revised (Transformer Ownership Allowance)	(3) Revised for Corrections	(4) Proposed for Test Year	(5) Board Target Range
Residential	106.80	108.59	104.94	104.22	85 - 115
GS < 50 kW	103.75	105.12	102.10	102.10	80 - 120
GS > 50 kW	99.60	93.65	93.53	93.53	80 - 180
Street Lights	23.73	24.53	44.80	57.40	70 - 120
Sentinel Lights	32.71	33.35	38.41	54.21	70 - 120
USL	71.36	71.20	68.87	98.00	80 - 120

Table 7-1 outlines:

- **Column 1:** The revenue to cost ratios from Whitby Hydro's original Cost Allocation Informational Filing (CAIF) as submitted on February 28, 2007 (EB-2002-0001). A singular filing was prepared for Run 1 and Run 2 as Whitby Hydro had a previously existing USL class.
- **Column 2:** The revenue to cost ratios from the original CAIF adjusted for the Transformer Ownership Allowance as outlined in the Board's Filing Requirements.
- **Column 3:** The revenue to cost ratios from the original CAIF adjusted for the Transformer Ownership Allowance as outlined in the Board's Filing Requirements and model corrections (further details outlined in the applicable section below).
- **Column 4:** The revenue to cost ratios based on Whitby Hydro's proposed 2010 rates.
- **Column 5:** The Board-approved target ranges by rate class.

Table 7-2: Test Year Revenue Impacts – Appendix 2-P(b)

Customer Class	Current Revenue	Test Year Revenue Assuming Current Revenue to Cost Ratios	Test Year Revenue Assuming Proposed Revenue to Cost Ratios
Residential	11,998,836	13,016,530	12,913,963
GS < 50 kW	1,739,920	1,953,281	1,951,368
GS > 50 kW	3,740,692	4,542,149	4,537,700
Street Lights	239,528	256,179	327,907
Sentinel Lights	2,181	2,279	3,213
USL	126,358	86,028	122,295
Total	**17,847,514**	**19,856,446**	**19,856,446**

* excludes revenue offsets

Table 7-2 outlines:

- The current revenue dollar value, by customer class, based on existing rates.
- The test year revenue assuming current revenue to cost ratios (as per column 3 of Table 1), by customer class (adjusted proportionally for residual differences).
- The test year revenue assuming proposed revenue to cost ratios from Table 1, Column 4.

INITIAL COST ALLOCATION STUDY (1):

The data used in the Cost Allocation Model was consistent with Whitby Hydro's cost data that supported its 2006 OEB approved distribution rates (EDR). Details of the initial CAIF are as follows:

- The cost allocation model filed was prepared in accordance with the OEB issued guidelines.
- The historical test year (2004) was used in Whitby Hydro's 2006 Board approved EDR and the underlying 2004 trial balance formed the basis of the cost data used in the cost allocation filing.
- Whitby Hydro contracted with Hydro One to provide distributor specific load data profiles including weather normalization based on Hydro One's methodology.
- Whitby Hydro conducted its own residential appliance saturation survey, the results of which were utilized by Hydro One in preparing Whitby Hydro's load profiles.
- Whitby Hydro did not identify any costs to be directly allocated to a single customer rate class.
- Whitby Hydro does not have any bulk assets.

- Costs are tracked in USoA accounts by asset in a manner that allows for detailed allocation to sub-accounts. The tracking of assets at a detailed level allowed for depreciation and accumulated depreciation information to be analyzed in a similar fashion.
- Customer Data information incorporated the default weighting factors for Services and Billings with the exception of Streetlights for which the Services weighting was adjusted to 0.167 in an attempt to consider that one connection links multiple fixtures to the distribution system.
- Standard weighting factors for meter capital were used with the exception of costs for one meter type (single phase 200 Amp urban meter) to more accurately represent the weighted average installed cost. A cost of $65 was used.
- Meter Reading was adjusted to reflect ratios of actual costs for meter reading as obtained from the meter reader service provider used by Whitby Hydro.

A copy of sheet O1 from the model has been included as Attachment 7-1.

Results

A summary of the revenue to cost ratios by customer class is summarized in Table 7-1 (column 1). The initial CAIF suggested that ratios were within the OEB target ranges established in the Application of Cost Allocation for Electricity Distributors Report of the Board (EB-2007-0667) issued on November 28, 2007, for Residential, GS<50 kW, and GS> 50kW classes. The Streetlight, Sentinel light, and USL classes all showed some level of underfunding. Whitby Hydro did note in the Manager's Summary (filed as part of the Initial CAIF), that while this result did not appear unusual in comparison to other distributors, it was recommended that further analysis and review should be undertaken to better understand the results before any actions were taken. It was also noted that weather normalization does have a significant impact on the results especially for the Residential customer class.

INITIAL COST ALLOCATION STUDY WITH TRANSFORMER OWNERSHIP ALLOWANCE REMOVED (2):

Whitby Hydro's approved transformer allowance calculated through the 2006 EDR was $259,138. This amount was allocated to the GS>50 kW customer class.

In accordance with the Board's Filing Requirements, Whitby Hydro removed the "cost" associated with the transformer ownership allowance from the revenue requirement (worksheet I3) and also subtracted the "revenue" associated with the transformer ownership allowance from the approved revenue from the affected GS>50 kW customer rate class (worksheet I6, row 29). For this version of the 2006 CAIF, there were no other changes to the model as filed with the Board in 2007.

A copy of sheet O1 from the model has been included as Attachment 7-2.

Results

The results of this adjustment for transformer ownership allowance generated the outcomes shown in Table 7-1 (column 2) which can be summarized as follows:

- The residential class's revenue to cost ratio increased from 106.8% to 108.59%
- The GS<50 kW revenue to cost ratio increased from 103.75% to 105.12%
- The GS>50 kW revenue to cost ratio decreased from 99.60% to 93.65%.
- The USL revenue to cost ratio had a small drop from 71.36% to 71.20%.
- Other class's revenue to cost ratios improved slightly – Streetlights moved from 23.73% to 24.53% and Sentinel Lights moved from 32.71% to 33.35%

In general, there was no change in how each customer class's results fit into the OEB target ranges. The Residential, GS<50 kW and GS>50 kW classes all remained within the range, while the Streetlight, Sentinel Light and USL classes fell below the target ranges.

INITIAL COST ALLOCATION STUDY WITH TRANSFORMER OWNERSHIP ALLOWANCE REMOVED AND INCLUDING MODEL CORRECTIONS (3):

As noted in the Manager's Summary section of Whitby Hydro's initial CAIF, there was some concern with regard to the customer classes which fell outside of the target ranges and it was recommended that these classes be reviewed further before the results were used for any specific purposes.

Whitby Hydro undertook a review of the class specific data to ensure that the data requirements had been understood and appropriately reflected in the model. During this review some model corrections were identified which served to improve the accuracy of the model outputs. Given that the results of the Cost Allocation study were no longer strictly "informational" and were now being relied on to form part of the underlying basis for updates required to Cost of Service applications, it was reasonable and necessary to ensure this type of review was conducted.

In addition to the transformer ownership allowance correction identified by the Board, the following model corrections were made:

- Meter Reading counts on sheet I7.2 were corrected to reflect the number of times each meter read activity occurred.
- Sheet I6 was corrected to remove the weighting factor on the Streetlighting services to return it to the default value.
- Sheet I6 was corrected for Streetlight connections and Sentinel light connections.
- Sheet I6 was corrected for the Sentinel lights class to reflect the number of bills based on the customer count in that class.

- Sheet I6 was corrected for the USL customer count which had been understated.

Additional detail regarding the review undertaken for Streetlight and Sentinel light connections is described in a separate section.

A copy of sheet O1 from the model has been included as Attachment 7-3.

Results

The revenue to cost ratios are reflected in Table 7-1 (column 3). In general, there was no change in how each customer class's results fit into the OEB target ranges. The Residential, GS<50 kW and GS>50 kW classes all remained within the range, while the Streetlight, Sentinel Light and USL classes fell below the target ranges. It was noted however, that all classes (with the exception of USL and GS > 50kW) showed some improvement by moving closer to a revenue to cost ratio of 100%.

PROPOSED 2010 COST ALLOCATION MODEL (4):

Whitby Hydro retained the services of ERA to prepare an appropriate Cost Allocation Study for 2010. The approach taken by ERA was based on the Board's Filing Requirements and follows the cost allocation policies and guidelines issued by the Board.

In summary, the 2006 Cost Allocation model was updated to reflect the 2010 load forecast and costs for the test year using the 2010 test year trial balance information. The load shape developed by Hydro One for the 2006 Cost Allocation study was maintained but scaled to match the 2010 load forecast. Customer, Meter and Demand data were also updated and/or scaled to reflect 2010 test year data. As directed by the Board, the transformer ownership allowance adjustment was incorporated into the model. Further details of the proposed 2010 cost allocation study and underlying assumptions can be found in ERA's report. (Attachment 7-5)

A copy of sheet O1 from the model has been included as Attachment 7-4.

Results

The proposed 2010 revenue to cost ratios are reflected in Table 7-1 (column 4). Whitby Hydro designed these ratios with the following objectives in mind:

- All customer classes within the Board's target range should remain so, and any adjustments to these classes should be designed to move them closer to 100%.
- Any customer classes outside of the range should move towards the range by 50% of the difference between the starting point and the closest end of the target range. Any variations to this would require further explanation.

- Adjustments required to those classes that were below the range, should be offset by those classes which were the furthest above the range first, and then shared to bring classes closer to 100% cost recovery in a consistent manner.
- Bill impacts should be reviewed to determine if rate mitigation is a consideration.

The analysis and results by customer class are as follows:

Classes currently above the target range:

- Not applicable

Classes currently below the target range:

- Street Lights – move from current 44.80% to proposed 57.40%
- Sentinel Lights – move from current 38.41% to proposed 54.21%

For both of these classes, this represents a movement of 50% towards the lower end of the target range. Whitby Hydro proposes to move the remaining 50% evenly over the subsequent two year period (2011 and 2012). Using this approach, the total bill impact for the Streetlight class remains below 10%. The Sentinel light class's total bill impact is approximately 15% -17% which suggests mitigation is required. However, Whitby Hydro submits that the total dollar impact of roughly $2-$4 per month is not material especially considering that billing for Sentinel light customers is typically combined on a Residential, General Service or Streetlight bill which reduces the overall impact (% change) on the total bill.

- USL – move from current 68.87% to proposed 98.00%

Whitby Hydro proposes to move the USL class to a revenue to cost ratio of 98%. This takes the class from below the target range to close to 100%. The reason for a more significant shift into the target range can be rationalized given the changes that have occurred in the billing practices for this class since the Initial Cost Allocation time period. In the USL class, there are customers that either have already, or are planned to be changed to consolidated billing by 2010. As a result, the costs allocated to this class in the 2010 Cost Allocation Study have reduced considerably. This adjustment in costs has allowed Whitby Hydro to move the class to just below the revenue to cost ratio of 100% while still generating bill reductions. This decision has also allowed the Residential class (which has the revenue to cost ratio furthest above 100%) to reduce their level of overfunding.

Classes currently within the target range:

- Residential – move from current 104.94% to proposed 104.22%.

This class was already within the target range but it is the class with the revenue to cost ratio that is furthest above 100%. As a result, any offsetting adjustments for classes that were below the target range were used to reduce the level of over-funding by the Residential class.

- GS<50 kW – no change from current to proposed (remains at 102.10%).
- GS>50 kW – no change from current to proposed (remains at 93.53%).

CONNECTIONS – REVIEW OF STREETLIGHT, SENTINEL LIGHT AND USL:

As identified in the original cost allocation filing, Whitby Hydro had some concerns with respect to the revenue to cost ratios for the Streetlight, Sentinel light and USL classes. For these classes, it was determined that the number of connections could be affected by different design configurations which have a resulting impact on the weighted services allocators utilized in the Cost Allocation model. While it was recognized that design configurations would likely impact the Street light class most significantly, all of these classes were analyzed to ensure model inputs were reasonable. The results have been summarized below and incorporated into the Cost Allocation models where noted.

<u>Streetlight Connections</u>

The results of the Streetlight configuration review were discussed in Exhibit 3 (forecast of future customer growth) and have been included again given their relevance and impact to the 2010 cost allocation study.

Whitby Hydro is a well established electricity distribution company that was formed in 1903. As technology has changed over the years, so has the way in which Whitby Hydro conducts business and builds and services infrastructure. In this regard, Whitby Hydro has a number of configurations related to the manner in which streetlights have been connected to Whitby Hydro's distribution system over time. These connections range from a single connection of a streetlight to an overhead transformer or secondary bus, to a large number of lights connected though a service pedestal in underground residential subdivisions requiring only one connection to a transformer.

All of the streetlights now being designed and connected in new residential subdivisions allow as many as ten streetlights energized though a single connection to the distribution system.

In January 2009, Whitby Hydro reviewed records and data from its Geographic Information System (GIS) to determine how the individual street lights owned and maintained by the Town of Whitby are connected to the distribution system. The results of this analysis yielded an overall ratio of lights to connections of 3.2 to 1. A breakdown of the actual results at the time of the review as well as projections for 2009 and 2010, are outlined in Table 7-3 below:

Table 7-3: Streetlight Connections – Breakdown of Streetlight Configurations

	as of January 2009		2009 Forecast		2010 Forecast	
Description	**No. of Lights**	**No. of Connections**	**No. of Lights**	**No. of Connections**	**No. of Lights**	**No. of Connections**
Individual Streetlights on Existing Hydro Poles or Other:						
a. Fed from Overhead Secondary Bus	2,588	1,074	2,588	1,074	2,598	1,084
b. Fed from Underground Secondary Bus	201	93	201	93	201	93
c. Fed from Streetlight Conductor	1,247	74	1,283	79	1,283	79
Individual Streetlight Poles fed from Underground Streetlight Conductor	6,160	2,258	6,174	2,260	6,174	2,260
Streetlights fed from Underground Streetlight Pedestals	1,060	80	1,111	85	1,308	95
Metal Halide Floodlights	17	5	17	5	17	5
TOTAL	**11,273**	**3,584**	**11,374**	**3,596**	**11,581**	**3,616**
Ratios		***3.2***		***3.2***		***3.2***

The ratio of 3.2:1 will continue to increase as new underground serviced residential subdivisions are developed and older subdivisions undergo cable rehabilitation bringing older construction techniques up to contemporary standards.

While an attempt was made during the initial Cost Allocation filing to incorporate a weighting for connections which links multiple streetlight fixtures to the distribution system, only the service weighting was adjusted (on sheet I6) but not the number of connections. At the time of the initial cost allocation filing, it was estimated that a 6:1 ratio was appropriate however, after the January 2009 review, it was apparent that a 3.2:1 ratio is more reflective of the total system configuration. While a 6:1 ratio was reasonable based on average design standards at the time, it did not fully take into account the impact of the historically varied design configurations. On the basis of this analysis, which more appropriately considers the weighted average ratio of lights to connections for the overall system, Whitby Hydro calculated the streetlight connection figures for the 2010 Cost Allocation study. In addition, the Initial Cost Allocation-Adjusted model incorporates this ratio to correct the model for the streetlight connections. While this analysis took place in early 2009, it appears this ratio is relatively stable in total, and thus it is reasonable to use for the Initial Cost Allocation-Adjusted model.

<u>Sentinel Lights</u>

Whitby Hydro has made efforts to review sentinel light ownership/configuration of equipment and to encourage individual metering of these services. Given its relevance to Cost Allocation, this review included an assessment of the current configuration of connections per customer. In general, it was determined that with the exception of those sentinel lights owned by the Town of Whitby, the remaining sentinel lights are configured in a manner which would result in one connection point per customer. The results of the analysis by customer class are provided in Table 7-4 below:

Table 7-4: Sentinel Light Analysis of Connections

	Analysis for	
	2010 Test Year	Initial Cost Allocation-Adjusted
# Sentinel Lights	37	79
# Connections	29	61
Ratio	1.28	1.30

The 2010 Cost Allocation model reflects 29 connections for this customer class. When this approach is used on the original Cost Allocation data, the result is 61 connections and a ratio of 1.30.

USL

These customer connections consist mainly of bill board sign lights, bus shelters, cable TV amplifiers and municipal intersection signalization. In terms of connections, it was noted that the number of devices and number of connections would be consistent and as a result no additional analysis for USL connections was required.

CONCLUSION:

The results from the Initial CAIF filed in February 2007 as well as those from the additional revisions to the initial model (for transformer ownership allowance and other model corrections) showed that the revenue to cost ratios for the Residential, GS<50 kW and GS>50 kW customer classes fell within the target range identified by the Board. The models showed that the Streetlight, Sentinel light and USL classes fell below the target range, suggesting that they were under-funding the costs that had been attributed to them.

Whitby Hydro has proposed 2010 revenue to cost ratios which are fair and reasonable given the following:

- The methodology and underlying assumptions utilized in the 2010 Cost Allocation study result in a fair allocation of costs.
- 2010 revenue to cost ratios maintain the Residential, GS<50 kW and GS>50 kW classes within the Board's target ranges and move the USL class into the target range.
- Revenue to cost ratios for the Streetlight and Sentinel light classes will move 50% towards the target range in 2010 with the remainder to take place equally over the subsequent two year period so that these classes will fall within the target range by 2012.
- Total bill impacts are less than 10% for all rate classes with the exception of Sentinel lights which has been addressed earlier this Exhibit under the proposed 2010 Cost Allocation model section.

ATTACHMENTS

Attachment 7-1: Initial Cost Allocation Study (Sheet O1)

2006 COST ALLOCATION INFORMATION FILING
WHITBY HYDRO ELECTRIC CORPORATION
EB-2005-0435 EB-2007-0001
Wednesday, February 28, 2007
Sheet O1 Revenue to Cost Summary Worksheet - First Run (and 2nd Run)

Ontario

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue (sale)	**$16,404,819**	$10,690,196	$1,688,237	$3,725,591	$210,390	$3,398	$87,007
mi	Miscellaneous Revenue (mi)	**$894,721**	$632,363	$103,415	$127,968	$13,779	$254	$16,942
	Total Revenue	**$17,299,540**	**$11,322,559**	**$1,791,652**	**$3,853,559**	**$224,169**	**$3,652**	**$103,949**
	Expenses							
di	Distribution Costs (di)	**$2,402,055**	$1,411,809	$208,954	$621,635	$148,216	$1,663	$9,778
cu	Customer Related Costs (cu)	**$2,255,998**	$1,527,290	$349,213	$306,845	$14,897	$485	$57,269
ad	General and Administration (ad)	**$2,345,317**	$1,479,479	$280,649	$467,935	$82,526	$1,085	$33,643
dep	Depreciation and Amortization (dep)	**$3,497,331**	$2,115,575	$302,180	$823,128	$238,202	$2,749	$15,495
INPUT	PILs (INPUT)	**$1,874,649**	$1,121,650	$161,534	$454,792	$127,115	$1,429	$8,128
INT	Interest	**$2,196,946**	$1,314,489	$189,306	$532,982	$148,969	$1,675	$9,526
	Total Expenses	**$14,572,296**	**$8,970,293**	**$1,491,835**	**$3,207,317**	**$759,925**	**$9,085**	**$133,840**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	**$2,727,244**	$1,631,780	$235,000	$661,633	$184,927	$2,079	$11,825
	Revenue Requirement (includes NI)	**$17,299,540**	$10,602,073	$1,726,835	$3,868,950	$944,853	$11,164	$145,665
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	**$92,510,745**	$56,056,906	$7,997,622	$21,644,335	$6,328,038	$73,033	$410,811
gp	General Plant - Gross	**$9,549,705**	$5,735,361	$823,312	$2,276,259	$665,958	$7,296	$41,520
accum dep	Accumulated Depreciation	**($41,855,706)**	($25,634,510)	($3,630,484)	($9,570,247)	($2,795,559)	($34,334)	($190,572)
co	Capital Contribution	**($9,376,247)**	($5,733,803)	($810,439)	($2,041,811)	($741,647)	($7,241)	($41,307)
	Total Net Plant	**$50,828,497**	**$30,423,955**	**$4,380,011**	**$12,308,537**	**$3,456,790**	**$38,753**	**$220,451**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	**$57,978,219**	$23,157,202	$5,431,635	$28,726,882	$563,147	$5,963	$93,390
	OM&A Expenses	**$7,003,370**	$4,418,579	$838,815	$1,396,415	$245,638	$3,232	$100,690
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0
	Subtotal	***$64,981,589***	***$27,575,781***	***$6,270,450***	***$30,123,297***	***$808,785***	***$9,196***	***$194,080***
	Working Capital	**$9,747,238**	**$4,136,367**	**$940,567**	**$4,518,495**	**$121,318**	**$1,379**	**$29,112**
	Total Rate Base	**$60,575,735**	**$34,560,322**	**$5,320,579**	**$16,827,031**	**$3,578,108**	**$40,132**	**$249,563**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$30,287,867**	**$17,280,161**	**$2,660,289**	**$8,413,516**	**$1,789,054**	**$20,066**	**$124,782**
	Net Income on Allocated Assets	**$2,727,245**	**$2,352,266**	**$299,817**	**$646,242**	**($535,756)**	**($5,433)**	**($29,891)**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$2,727,245**	**$2,352,266**	**$299,817**	**$646,242**	**($535,756)**	**($5,433)**	**($29,891)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**100.00%**	106.80%	103.75%	99.60%	23.73%	32.71%	71.36%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$1**	$720,486	$64,817	($15,391)	($720,684)	($7,512)	($41,716)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	13.61%	11.27%	7.68%	-29.95%	-27.08%	-23.95%

Attachment 7-2: Initial Cost Allocation Study with Transformer Ownership Allowance Removed (Sheet O1)

2006 COST ALLOCATION INFORMATION FILING
WHITBY HYDRO ELECTRIC CORPORATION
EB-2005-0435 EB-2007-0001
Wednesday, February 28, 2007
Sheet O1 Revenue to Cost Summary Worksheet - First Run (and 2nd Run)

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue (sale)	**$16,145,681**	$10,690,196	$1,688,237	$3,466,453	$210,390	$3,398	$87,007
mi	Miscellaneous Revenue (mi)	**$894,721**	$632,362	$103,416	$127,971	$13,776	$254	$16,942
	Total Revenue	**$17,040,403**	**$11,322,558**	**$1,791,653**	**$3,594,424**	**$224,166**	**$3,652**	**$103,949**
	Expenses							
di	Distribution Costs (di)	**$2,142,917**	$1,240,869	$183,504	$583,509	$124,863	$1,482	$8,690
cu	Customer Related Costs (cu)	**$2,255,998**	$1,527,290	$349,213	$306,845	$14,897	$485	$57,269
ad	General and Administration (ad)	**$2,345,317**	$1,475,536	$283,621	$475,112	$74,950	$1,053	$35,045
dep	Depreciation and Amortization (dep)	**$3,497,331**	$2,115,554	$302,196	$823,168	$238,161	$2,749	$15,503
INPUT	PILs (INPUT)	**$1,874,649**	$1,121,637	$161,544	$454,817	$127,089	$1,429	$8,133
INT	Interest	**$2,196,946**	$1,314,473	$189,317	$533,011	$148,939	$1,674	$9,531
	Total Expenses	**$14,313,158**	**$8,795,359**	**$1,469,396**	**$3,176,461**	**$728,899**	**$8,872**	**$134,172**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	**$2,727,244**	$1,631,760	$235,015	$661,669	$184,890	$2,079	$11,832
	Revenue Requirement (includes NI)	**$17,040,402**	$10,427,119	$1,704,411	$3,838,129	$913,789	$10,951	$146,004
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	**$92,510,745**	$56,056,580	$7,997,868	$21,644,929	$6,327,411	$73,030	$410,927
gp	General Plant - Gross	**$9,549,705**	$5,735,304	$823,354	$2,276,362	$665,849	$7,295	$41,540
accum dep	Accumulated Depreciation	**($41,855,706)**	($25,634,485)	($3,630,503)	($9,570,293)	($2,795,511)	($34,334)	($190,581)
co	Capital Contribution	**($9,376,247)**	($5,733,803)	($810,439)	($2,041,811)	($741,647)	($7,241)	($41,307)
	Total Net Plant	**$50,828,497**	**$30,423,597**	**$4,380,281**	**$12,309,188**	**$3,456,102**	**$38,750**	**$220,579**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	**$57,978,219**	$23,157,202	$5,431,635	$28,726,882	$563,147	$5,963	$93,390
	OM&A Expenses	**$6,744,232**	$4,243,695	$816,338	$1,365,465	$214,710	$3,020	$101,004
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0
	Subtotal	***$64,722,451***	***$27,400,897***	***$6,247,972***	***$30,092,347***	***$777,857***	***$8,983***	***$194,394***
	Working Capital	**$9,708,368**	**$4,110,135**	**$937,196**	**$4,513,852**	**$116,678**	**$1,347**	**$29,159**
	Total Rate Base	**$60,536,864**	**$34,533,731**	**$5,317,477**	**$16,823,040**	**$3,572,781**	**$40,098**	**$249,738**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$30,268,432**	**$17,266,866**	**$2,658,738**	**$8,411,520**	**$1,786,390**	**$20,049**	**$124,869**
	Net Income on Allocated Assets	**$2,727,245**	**$2,527,199**	**$322,258**	**$417,964**	**($504,733)**	**($5,220)**	**($30,223)**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$2,727,245**	**$2,527,199**	**$322,258**	**$417,964**	**($504,733)**	**($5,220)**	**($30,223)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**100.00%**	108.59%	105.12%	93.65%	24.53%	33.35%	71.20%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$1**	$895,439	$87,243	($243,705)	($689,622)	($7,299)	($42,055)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.01%	14.64%	12.12%	4.97%	-28.25%	-26.04%	-24.20%

Attachment 7-3: Initial Cost Allocation Model Adjusted for Transformer Ownership Allowance and Including Model Corrections (Sheet O1)

2006 COST ALLOCATION INFORMATION FILING
WHITBY HYDRO ELECTRIC CORPORATION
EB-2005-0435 EB-2007-0001
Wednesday, February 28, 2007
Sheet O1 Revenue to Cost Summary Worksheet - First Run (and 2nd Run)

Ontario

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$16,145,681	$10,690,196	$1,688,237	$3,466,453	$210,390	$3,398	$87,007
mi	Miscellaneous Revenue (mi)	$894,721	$638,539	$103,691	$127,821	$7,448	$205	$17,018
	Total Revenue	$17,040,403	$11,328,735	$1,791,928	$3,594,274	$217,838	$3,603	$104,025
	Expenses							
di	Distribution Costs (di)	$2,142,917	$1,295,258	$185,665	$581,427	$69,940	$1,276	$9,350
cu	Customer Related Costs (cu)	$2,255,998	$1,504,448	$371,050	$317,202	$5,550	$372	$57,376
ad	General and Administration (ad)	$2,345,317	$1,492,651	$296,370	$479,494	$40,463	$882	$35,456
dep	Depreciation and Amortization (dep)	$3,497,331	$2,223,149	$306,854	$820,522	$127,643	$2,366	$16,798
INPUT	PILs (INPUT)	$1,874,649	$1,180,186	$164,113	$453,361	$66,914	$1,237	$8,839
INT	Interest	$2,196,946	$1,383,088	$192,328	$531,305	$78,418	$1,449	$10,358
	Total Expenses	$14,313,158	$9,078,780	$1,516,379	$3,183,311	$388,929	$7,582	$138,177
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,727,244	$1,716,937	$238,752	$659,551	$97,347	$1,799	$12,859
	Revenue Requirement (includes NI)	$17,040,402	$10,795,717	$1,755,131	$3,842,862	$486,276	$9,381	$151,035
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$92,510,745	$58,917,360	$8,121,064	$21,574,836	$3,389,278	$62,869	$445,338
gp	General Plant - Gross	$9,549,705	$6,048,727	$837,381	$2,269,510	$342,434	$6,341	$45,311
accum dep	Accumulated Depreciation	($41,855,706)	($26,832,754)	($3,679,295)	($9,536,544)	($1,572,888)	($29,233)	($204,992)
co	Capital Contribution	($9,376,247)	($6,113,829)	($828,699)	($2,037,767)	($343,674)	($6,428)	($45,849)
	Total Net Plant	$50,828,497	$32,019,504	$4,450,451	$12,270,035	$1,815,149	$33,550	$239,808
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$57,978,219	$23,157,202	$5,431,635	$28,726,882	$563,147	$5,963	$93,390
	OM&A Expenses	$6,744,232	$4,292,357	$853,085	$1,378,123	$115,954	$2,531	$102,182
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$64,722,451*	*$27,449,559*	*$6,284,720*	*$30,105,005*	*$679,101*	*$8,494*	*$195,572*
	Working Capital	$9,708,368	$4,117,434	$942,708	$4,515,751	$101,865	$1,274	$29,336
	Total Rate Base	$60,536,864	$36,136,938	$5,393,159	$16,785,785	$1,917,014	$34,824	$269,144
		Rate Base Input equals Output						
	Equity Component of Rate Base	$30,268,432	$18,068,469	$2,696,580	$8,392,893	$958,507	$17,412	$134,572
	Net Income on Allocated Assets	$2,727,245	$2,249,956	$275,549	$410,964	($171,092)	($3,979)	($34,152)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,727,245	$2,249,956	$275,549	$410,964	($171,092)	($3,979)	($34,152)
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	104.94%	102.10%	93.53%	44.80%	38.41%	68.87%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$1	$533,019	$36,797	($248,588)	($268,438)	($5,778)	($47,011)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.01%	12.45%	10.22%	4.90%	-17.85%	-22.85%	-25.38%

Attachment 7-4: 2010 Cost Allocation Study (Sheet O1)

2010 COST ALLOCATION INFORMATION FILING
WHITBY HYDRO ELECTRIC CORPORATION
EB-2005-0435 EB-2007-0001
Wednesday, February 28, 2007
Sheet O1 Revenue to Cost Summary Worksheet - First Run (and 2nd Run)

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue (sale)	**$17,847,515**	$11,998,836	$1,739,920	$3,740,692	$239,528	$2,181	$126,358
mi	Miscellaneous Revenue (mi)	**$890,743**	$641,220	$93,338	$141,284	$7,031	$92	$7,779
	Total Revenue	**$18,738,258**	**$12,640,056**	**$1,833,258**	**$3,881,976**	**$246,559**	**$2,273**	**$134,137**
	Expenses							
di	Distribution Costs (di)	**$3,290,466**	$2,029,960	$263,324	$864,415	$114,285	$1,154	$17,328
cu	Customer Related Costs (cu)	**$2,722,615**	$1,844,416	$438,094	$395,838	$11,873	$243	$32,151
ad	General and Administration (ad)	**$2,906,340**	$1,871,666	$337,732	$611,058	$61,408	$679	$23,798
dep	Depreciation and Amortization (dep)	**$4,929,391**	$3,098,021	$402,237	$1,227,884	$173,896	$1,764	$25,590
INPUT	PILs (INPUT)	**$1,194,924**	$725,574	$97,554	$328,021	$37,560	$378	$5,838
INT	Interest	**$3,274,839**	$1,988,526	$267,358	$898,983	$102,938	$1,035	$16,000
	Total Expenses	**$18,318,575**	**$11,558,163**	**$1,806,298**	**$4,326,198**	**$501,959**	**$5,252**	**$120,705**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	**$2,428,614**	$1,474,687	$198,272	$666,684	$76,338	$767	$11,866
	Revenue Requirement (includes NI)	**$20,747,189**	$13,032,850	$2,004,570	$4,992,882	$578,298	$6,019	$132,570
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	**$142,007,090**	$89,345,036	$11,646,142	$35,308,758	$4,919,744	$49,995	$737,415
gp	General Plant - Gross	**$11,942,062**	$7,384,391	$976,911	$3,126,541	$389,926	$3,948	$60,344
accum dep	Accumulated Depreciation	**($71,676,723)**	($45,856,154)	($5,892,819)	($16,895,625)	($2,623,350)	($26,743)	($382,032)
co	Capital Contribution	**($18,155,373)**	($11,884,148)	($1,494,885)	($4,003,091)	($664,766)	($6,865)	($101,618)
	Total Net Plant	**$64,117,057**	**$38,989,126**	**$5,235,350**	**$17,536,583**	**$2,021,554**	**$20,336**	**$314,109**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	**$68,963,116**	$28,371,759	$6,084,779	$33,565,087	$736,061	$3,511	$201,919
	OM&A Expenses	**$8,919,421**	$5,746,042	$1,039,150	$1,871,311	$187,566	$2,076	$73,277
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0
	Subtotal	***$77,882,537***	***$34,117,802***	***$7,123,929***	***$35,436,398***	***$923,628***	***$5,587***	***$275,195***
	Working Capital	**$11,682,381**	**$5,117,670**	**$1,068,589**	**$5,315,460**	**$138,544**	**$838**	**$41,279**
	Total Rate Base	**$75,799,437**	**$44,106,796**	**$6,303,939**	**$22,852,043**	**$2,160,098**	**$21,174**	**$355,388**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$37,899,719**	**$22,053,398**	**$3,151,970**	**$11,426,021**	**$1,080,049**	**$10,587**	**$177,694**
	Net Income on Allocated Assets	**$419,683**	**$1,081,893**	**$26,959**	**($444,223)**	**($255,401)**	**($2,978)**	**$13,433**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$419,683**	**$1,081,893**	**$26,959**	**($444,223)**	**($255,401)**	**($2,978)**	**$13,433**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**90.32%**	96.99%	91.45%	77.75%	42.64%	37.77%	101.18%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($2,008,931)**	($392,794)	($171,313)	($1,110,906)	($331,739)	($3,746)	$1,567
	RETURN ON EQUITY COMPONENT OF RATE BASE	1.11%	4.91%	0.86%	-3.89%	-23.65%	-28.13%	7.56%

Attachment 7-5: Elenchus Research Associates - 2010 Cost Allocation Study for Whitby Hydro Electric Corporation

Whitby Hydro Electric Corporation
2010 Cost Allocation Study
A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Whitby Hydro Electric Corporation

December 2009

elenchus

Introduction

Whitby Hydro Electric Corporation ("Whitby") has prepared its 2010 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the May 27, 2009 update to the document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements").

Section 2.8 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

A completed cost allocation study using the Board approved methodology must be filed whether the applicant proposes to use it or not. This filing must

- *reflect future loads and cost and be supported by appropriate explanations;*
- *be corrected for transformer ownership allowance ..., and*
- *be presented in the form of an Excel spreadsheet.*[4]

The Filing Requirements also state that:

The Board expects the filings made by the applicant will follow the cost allocation policies reflected in the Board's report of November 28, 2007, Application of Cost Allocation for Electricity Distributors (EB-2007-0667).

Whitby asked Elenchus Research Associated (ERA)[5] to assist it by preparing an appropriate cost allocation study for its 2010 cost of service rate application. In addressing this issue, ERA was guided by the Filing Requirements and the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors".[6]

The CA Application Report observes at page 2 that:

The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report.

The "influencing factors" discussed in section 2.3 of the report are:

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[4] *Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009,* p. 19.

[5] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Whitby and documented in this report. John Todd's curriculum vitae is available at www.era-inc.ca.

[6] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5)
- **Limited modelling experience:** The Board observed that "the cost allocation model is complex, and the data required for the model was not always readily available for modelling." (p. 6)
- **Status of current rate classes:** The Board points out that "Any changes in customer classification or load data could have a significant impact on future cost allocation studies" (p. 6).
- **Managing the movement of rates closer to allocated costs:** The Board notes:

  > *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (p. 6)*

In utilizing the Board's cost allocation model for Whitby's 2010 cost allocation study, ERA has been cognizant of these "influencing factors" as they apply to Whitby.

Purpose of the Cost Allocation Study

In the context of a cost of service rate application based on a 2010 forward test year, the primary purpose of the cost allocation study ("CA Study") is to determine the proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, the desired results can be achieved in either of two ways.

- **Prospective Year CA Study:** A cost allocation study for the 2010 test year can be based on an allocation of the 2010 test year costs (i.e., the 2010 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Assuming there is a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.
- **Historic Year CA Study:** As an alternative, an historic year cost allocation study can be prepared that determines the proportion of costs allocated to each class for the most recent historic year. In the case, the CA Study will rely on actual costs, weather adjusted loads, customer counts, etc. that are not affected by forecast errors. Assuming the costs and loads are relatively stable so that the proportionate cost responsibility of each rate class in the historic year is a reasonable proxy for the 2010 test year cost responsibility, the resulting proportionate cost responsibilities can be used to allocate the 2010 revenue requirement to the various classes.

The Whitby CA Study uses the first of these methods in order to ensure compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". Relying on a Prospective Year CA Study is also appropriate at this time since the Ontario economy has suffered over the past two years and, as a result, many distributors have experienced significant changes in the load profiles of their customer classes. These changes could have a significant impact on the allocation of costs to the classes and the resulting revenue to cost ratios. This approach implicitly assumes that the economic recovery will be slow and, as a result, the relative loads of customer classes are more likely to reflect 2010 loads than 2008 loads during the next IRM cycle.

Whitby's 2006 Cost Allocation Information Filing

Whitby filed its 2006 Cost Allocation Information Filing ("CAIF") on February 28, 2007, using 2004 financial information. Whitby's 2006 CAIF relied on the Board's 2006 Cost Allocation Model ("CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions").

Structure of the Report

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Whitby CA Study, explaining each of the model runs (or version of the CA model) included in the study, as well as the load and cost information used for each run. Section 3 explains the methodology used to develop the 2010 Whitby model by documenting each step taken in completing the model. Section 4 summarizes the results of the Whitby CA Study, showing the class revenue requirements and revenue to cost ratios generated by each version of the CA models.

Overview of the Whitby 2010 CA Study

There are several changes affecting the Whitby cost allocation results in 2010 as compared to the 2006 CAIF:

- In their 2006 CA Model, Whitby had used the number of meters subject to each type of read in the I7.2 Meter Reading table. This has been updated to reflect the number of reads required per year.
- In the 2006 CA Model, Whitby reported streetlight lamps in place of streetlight connections. The corresponding services weighting factor had been reduced in order to better reflect the relative

cost of servicing a streetlight. The number of connections has been updated to reflect an average of 3.2 streetlight lamps per connection, and the services weighting factor has been reset to default.

- Similar to the streetlamps concern, it was identified that occasionally multiple sentinel lights were using shared connections. The number of Sentinel light connections has been reduced from 79 to 61, and the number of bills has been reduced to 498 to reflect lamps sharing connections.
- The number of USL customers was understated in the 2006 CA Model. This has been updated to 176 customers.

Models Runs Included in the Whitby Cost Allocation Study

Section 2.8.3 of the updated Filing Requirements specifies that "three sets of revenue to cost ratios for each customer class" must be provided based on:

- "the initial cost allocation model" which is the 2006 cost allocation information filing ("CAIF");
- "the initial cost allocation model revised with the adjusted transformer ownership allowance" which is the 2006 cost allocation information filings, adjusted in accordance with section 2.8.2 of the updated Filing Requirements; and
- "the updated cost allocation model" which is the appropriate 2010 model.

Hence, the cost allocation studies prepared for purposes of all 2010 cost of service filings must include these three separate CA models. Furthermore, certain corrections to the CAIF input data were identified and incorporated into an additional version of the 2006 model. As a result, the Whitby Cost Allocation Study ("CA Study") consists of four versions of the OEB's cost allocation model. For clarity, the following designations are used.

- **WH-2006: Whitby 2006 Model**: The Whitby CAIF as filed in 2006.
- **WH-2006C1: Whitby 2006 Model with Corrected Transformer Ownership Allowance (TOA) treatment**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements.
- **WH-2006C2: Whitby 2006 Model Corrected for TOA and other items**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements was further corrected as follows:
    1. On Sheet I6 Customer Data, Row 33 – The weighting factor for streetlight services has been set back to the default value of 1.0.
    2. On Sheet I6 Customer Data, Row 36 – The streetlight connection count was updated to estimated connection counts based on an overall average of 3.2 lamps per connection.

3. On Sheet I6 Customer Data, Rows 36, 38, 40, 41, and 42 – The sentinel light connection and customer counts were updated to reflect that the 79 lamps were serving 61 customers with 61 connections in 2006.
4. On Sheet I6 Customer Data, Rows 30, 40, 41, and 42 – the USL customer count was updated to 176 to correct an error.
5. On Sheet I7.2 Meter Reading – All counts were based on number of meters read each way, rather than accounting for the number of times each meter had to be read. All values were multiplied by the number of reads per year.

- **WH-2010: Whitby 2010 Model**: The 2006 CAIF with the corrected treatment of the Transformer Ownership Allowance and 2010 loads, costs, and revenues.

Load and customer Information

The updated Filing Requirements specify that "the updated model must be consistent with the load forecast and costs in the test year ... If updated load profiles are not available, the load profiles of the classes may be the same as those used in the information filing scaled to match the load forecast." (Section 2.8.1, pp. 19-20) The Whitby 2010 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2010 load forecast and customer counts by class being used by Whitby in its application were also used for the 2010 CA models. Whitby's load forecast was prepared by ERA.
- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF was used for all classes

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2010 models for the following reasons.

1. ERA explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of Whitby-specific hourly load profiles. As far as ERA is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. There would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.

3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information will be available in the next few years at minimal incremental cost.

4. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter the hourly load profiles of the affected classes.

5. The 2006 hourly load profiles were based on 2004 actual loads and updated hourly load profiles would be based on 2008 actual loads. An update of the hourly load profiles after only 4 years (2004 to 2008) can be expected to produce changes in cost responsibility that are small relative to the tolerances that are necessary given the imprecision of the allocated costs based on the 2006 CA Model methodology. (The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time.)

6. There are no Intermediate or Large User customers in the Whitby service area.

Cost Information

As noted earlier, ERA's preferred methodology for preparing 2010 cost allocation models is to use the prospective 2010 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2010 test year. In the case of Whitby, the financial information for the forecast year has been prepared at the USoA level consistent with the level of detail embedded in the OEB's cost allocation model. [7]

[7] Some information (i.e., meter counts and some amortization detail) that is used in the Board's CA Model is not explicitly forecasted for the test year. These values were estimated using scaling factors based on prior year ratios. For example, the ratio of meters to customers was assumed to be constant. The portion of the total costs accounted for in this manner was too small for any plausible estimation errors to have a significant impact on the test year revenue to cost ratios.

Whitby Cost Allocation Study Methodology

This section documents ERA's methodology for the Whitby Cost Allocation Study which includes the 2006 models and the 2010 CA Model.

The uncorrected 2006 CAIF model (WH-2006) is an unaltered version of the model that was filed with the Board in 2007.

Corrected 2006 Whitby CA Model

As described in section 2.1, two additional versions of the 2006 Model were completed to apply certain corrections:

- **WH-2006C1:** This version of the Whitby CA Model was corrected only for the treatment of the transformer ownership allowance in accordance with the Filing Requirements, section 2.8.2.

- **WH-2006C2:** This version of the Whitby CA Model was corrected not only for the treatment of the transformer ownership allowance, but also for five errors that were identified in the original 2006 Whitby CAIF. This version is the appropriate basis for examining the impact of the rates proposed for Whitby on the revenue to cost ratios by class, as compared to the 2006 revenue to cost ratios.

Since the appropriate version of the Whitby 2006 CAIF to be used for reference purposes in the Whitby application is WH-2006C2, ERA has modified the Revenue to Cost Ratio table set out in Appendix 2-P of the Filing Requirements by adding a column labelled "Column 2 Revised (Other Corrections)". This format for the table is used in the Summary of Revenue to Cost Ratios in section 4 below. The WH-2006C2 revenue to cost ratios should be used in assessing the direction and magnitude of changes in the revenue to cost ratios from 2006 to 2010.

2010 Whitby CA Model

Hourly Load Profile (HONI File)

For the Whitby CAIF, HONI provided data files with three worksheets that were used as input to the 2006 CAIF:

- **Data Summary:** actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.

- **Hourly Load Shape by Class:** GWh by class for each hour in 2004.

- **Input to Cost Allocation Model**: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Whitby hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2010. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2010 load forecast while maintaining the hourly load shapes.

Demand Allocators (HONI File)

The demand allocators used in the WH-2010 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2010 hourly load profiles resulting from the preceding step. Using the 2010 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

2010 Demand Data (WH-2010 Model)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2010 Whitby CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) for GS > 50 are not equal to the full class NCP values since not all GS>50 customers use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

2010 Customer Data (WH-2010 Model)

The 30 year weather normalized kWh by rate class which was an input from the Hydro One file at Sheet I6 Customer Data row 27 in the 2006 CA model was replaced with the 2010 load forecast in the 2010 CA Model.

In addition, the demand data (kW and kWh) in rows 21, 22, 25, and 56 of Sheet I6 Customer Data were replaced with the forecasted values. Row 23 was scaled by the percentage change in row 22.
The 2010 Distribution Revenue in row 29 was derived using the forecast demand (kW and kWh) and customer counts by rate class and the existing 2009 rates.

2010 Revenue to Cost Ratios

Since Whitby is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2010. The 2010 total revenue to cost ratio at current rates is less than 100% by the amount of the required rate increase. The revenue to cost ratios of the classes reflect the costs allocated to the classes based on the OEB CA Model methodology and the revenues that would be generated at current rates given the forecast demand (kW and kWh) and customer counts by rate class for 2010.

Summary of Revenue to Cost Ratios

The class revenue-to-cost ratios as determined in the Whitby cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	WH-2006	WH-2006C1	WH-2006C2	WH-2010 current rates	WH-2010 proposed rates	Board Target Range
Residential	106.80	108.59	104.94	96.99	104.22	85-115
GS < 50 kW	103.75	105.12	102.10	91.45	102.10	80-120
GS > 50 kW	99.60	93.65	93.53	77.75	93.53	80-180
Street Lighting	23.73	24.53	44.80	42.64	57.40	70-120
Sentinel	32.71	33.35	38.41	37.77	54.21	70-120
USL	71.36	71.20	68.87	101.18	98.00	80-120
Total	100.00	100.00	100.00	90.32	100.00	

Note that the total revenue to cost ratio for WH-2010 at current rates is less than 100% because it represents a revenue deficiency at current rates. The WH-2010 ratios at current rates reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2010 forecast test year. Whitby's proposed rates for 2010 alter the relative revenue to cost ratios of the classes.

EXHIBIT 8
RATE DESIGN

RATE DESIGN

OVERVIEW

This Exhibit explains the methodology used by Whitby Hydro in calculating and designing its proposed rates for the 2010 test year. The elements of rate design discussed in this section include:

- Fixed/Variable splits
- Transmission Service Rates
- Low Voltage Charges
- Loss Adjustment Factors
- Rate Schedule and Bill Impacts

The proposed revenue requirement takes the following amounts into consideration:

Service Revenue Requirement	20,747,189	
Less: Revenue Offsets	(890,743)	
Base Revenue Requirement		19,856,446
Add: Transformer Ownership Allowance	293,570	
Low Voltage Recovery	203,590	497,160
Gross Base Revenue Requirement		20,353,606

Exhibit 6 provides the calculations of the proposed 2010 Service Revenue Requirement and Base Revenue Requirement.

The allocation of revenue responsibility is determined on the basis of the 2010 Cost Allocation Study and the proposed revenue to cost ratios as outlined in Exhibit 7. Distribution revenue responsibility by customer class is provided in the tables below:

Table 8-1: Allocation of Base Revenue Requirement by Customer Class

Customer Class Name	Rate Application		
	Allocated Revenue [8]	Allocated Cost [8]	Proposed Revenue to Cost Ratio
Residential	12,913,963	12,391,630	1.04
General Service Less Than 50 kW	1,951,368	1,911,232	1.02
General Service 50 to 4,999 kW	4,537,700	4,851,598	0.94
Unmetered Scattered Load	122,295	124,791	0.98
Sentinel Lighting	3,213	5,927	0.54
Street Lighting	327,907	571,267	0.57
TOTAL	19,856,446	19,856,445	1.00

Table 8-2: Allocation of Gross Base Revenue Requirement

Customer Class Name	Total Base Revenue Requirement	Transformer Allowance Recovery [4]	Low Voltage Revenue Required [5]	Gross Base Revenue Requirement
Residential	12,913,963		95,268	13,009,231
General Service Less Than 50 kW	1,951,368		18,429	1,969,797
General Service 50 to 4,999 kW	4,537,700	293,570	87,566	4,918,836
Unmetered Scattered Load	122,295		612	122,907
Sentinel Lighting	3,213		9	3,221
Street Lighting	327,907		1,707	329,614
TOTAL	**19,856,446**	**293,570**	**203,590**	**20,353,606**

FIXED/VARIABLE PROPORTION

The purpose of this section is to describe the development of the fixed to variable proportions by customer class and outline the resulting calculations that were used to determine the proposed fixed and variable rates for the 2010 test year.

In developing the fixed/variable splits by customer class, Whitby Hydro took two primary factors into account:

- Existing fixed/variable split by customer class
- Lower and Upper Bounds identified for the Monthly Service Charge (MSC)

The existing fixed/variable percentage split was developed using the 2010 load data and applying the existing rates. Whitby Hydro is of the opinion that the resulting percentage splits should be used as the basis for the 2010 rate design unless there are circumstances which justify a different approach.

In the Board Report on the Application of Cost Allocation for Electricity Distributors issued on November 28, 2007, the Board described the necessary considerations for the treatment of monthly service charges. The Board maintained the view that the use of avoided costs is an appropriate basis for establishing the minimum or floor amount for the MSC. The same methodology was also applied to set a ceiling for the MSC based on the avoided costs plus the allocated customer costs.

Following the outlined approach, Whitby Hydro applied the existing fixed/variable percentages to the 2010 gross base revenue requirement for each customer class to develop an initial starting point for the MSC using the load forecast information. The results were reviewed against the lower and upper bounds set by the 2010 Cost Allocation Study.

In taking this approach, only two of the calculated MSCs (Residential and GS>50 kW) were above the ceiling established in the 2010 Cost Allocation Study. The charges for the remaining classes stayed within the upper and lower bounds established for the MSC. In order to adjust the rates to remain within the established bounds, the Residential MSC was reduced slightly to a level below the upper bound while maintaining a fixed/variable split close to the existing proportions. Whitby considered retaining the existing MSC for the Residential Class however, that rate would not sufficiently preserve the existing fixed/variable proportions which was one of the primary factors of consideration in Whitby Hydro's rate design.

The GS>50kW class also required an adjustment to bring the MSC below the upper bounds as recommended in the Board Report. The existing MSC was maintained as it fell slightly below the upper bound and the resulting fixed/variable split was very close to the existing proportions set by the upper bounds.

The existing and proposed fixed rates and proportional splits are included in Tables 8-3 and 8-4 below along with the floor and ceiling ranges. Note that these rates do not include Smart Meter funding adders, or any other proposed rate riders.

Table 8-3: Existing and Proposed Monthly Service Charge Rates

	Existing Rates			Proposed Rates		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$16.71	60.67%	39.33%	$17.62	60.02%	39.98%
General Service Less Than 50 kW	$18.51	23.77%	76.23%	$20.44	23.77%	76.23%
General Service 50 to 4,999 kW	$191.34	23.46%	76.54%	$191.34	20.31%	79.69%
Unmetered Scattered Load	$9.97	36.60%	63.40%	$9.59	36.61%	63.39%
Sentinel Lighting	$2.87	57.77%	42.23%	$4.19	57.75%	42.25%
Street Lighting	$1.04	58.74%	41.26%	$1.40	58.50%	41.50%

Table 8-4: 2010 Cost Allocation – Monthly Service Charge Floor and Ceiling

	MSC Floor	MSC Ceiling	Proposed	Change vs
Customer Class Name	**Rate**	**Rate**	**Rate**	**Existing Rate**
Residential	$2.51	$17.71	$17.62	$0.91
General Service Less Than 50 kW	$12.96	$42.28	$20.44	$1.93
General Service 50 to 4,999 kW	$58.60	$192.34	$191.34	$0.00
Unmetered Scattered Load	$2.73	$19.24	$9.59	($0.38)
Sentinel Lighting	$0.38	$11.30	$4.19	$1.32
Street Lighting	$0.27	$11.42	$1.40	$0.36

Once the proposed MSCs were established, the volumetric charges become a function of the remaining gross base revenue requirement and the load forecast variables. The resulting rates have been highlighted in Table 8-5.

1 **Table 8-5: 2010 Existing and Proposed Variable Rates**

		Variable Rates	
Customer Class Name	**Per**	**Existing**	**Proposed**
Residential	kWh	$0.0137	$0.0148
General Service Less Than 50 kW	kWh	$0.0181	$0.0200
General Service 50 to 4,999 kW	kW	$3.3729	$4.0566
Unmetered Scattered Load	kWh	$0.0325	$0.0312
Sentinel Lighting	kW	$7.7629	$11.3413
Street Lighting	kW	$4.1309	$5.6149

RETAIL TRANSMISSION SERVICE RATES

On July 21, 2009, the Board issued its *Revision to Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates*. This revision outlined the information that the Board requires an electricity distributor to file for approval to adjust its retail transmission service rates (RTSRs) starting with the 2010 rate applications. Whitby Hydro has followed the Board's Guideline G-2008-0001 in the preparation of this application.

OVERVIEW

Whitby Hydro proposes to make changes to its 2010 RTSRs based on an analysis of historical trends and the impact of resetting the total loss factor (TLF) used for billing customers. The rate adjustments essentially align the transmission revenue collected with the transmission costs incurred as closely as possible in order to minimize future balances in the transmission variance accounts (RSVAs).

Whitby Hydro proposes an increase to its Network Services rates (6.38% for kWh billed customer classes and 4.91% for kW billed customer classes) and a decrease to its Connection Services rates (4.4% for kWh billed customer classes and 5.87% for kW billed customer classes). While the net impact of these changes is minimal, Whitby Hydro decided that it was worthwhile to re-align the rates to ensure that they are more reflective of the individual wholesale costs which they are intended to recover. The proposed rates by rate class are shown in Table 8-8.

As part of this application, Whitby Hydro also proposes to eliminate the GS>50 kW transmission rates for interval metered customers. The interval meter specific rates were originally designed to accommodate customers that were both primary metered and interval metered. Upon review, Whitby Hydro determined that this rate distinction was no longer required, since with a primary metering allowance for transformer losses (as approved by the Board), transmission rates can be adjusted to produce the same results that the separate interval meter rates were originally designed to accomplish.

In its *Revision to Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates*, the Board communicated that additional changes to the Ontario Uniform Transmission Rates (UTRs) are expected effective January 1, 2010. Whitby Hydro anticipates that this change may have an impact on the appropriateness of RTSRs moving forward. In light of this, Whitby Hydro expects that the Board may require additional review and adjustments at that time to incorporate the impact of any UTR decision.

BACKGROUND

Whitby Hydro has two sources of wholesale transmission charges which are differentiated by the type of connection. Where its facilities are directly connected to the provincial transmission system, Whitby Hydro receives transmission charges from the Independent Electricity System Operator (IESO) based on the current UTRs. Whitby Hydro also has facilities that are partially embedded within Hydro One Networks (HONI), for which charges are applied based on HONI's RTSRs. The weighting of the load between these two types of connection facilities has begun to shift over the past several years, with approximately 70-75% of the load in 2008 and 2009 being provided at UTRs. This increase is due in large part to new feeder capacity being added late in 2007 to the directly connected location, coupled with other load and system planning requirements and strategies. Previously when the load was more equally balanced between connection locations, the impact of UTR changes was not as significant, however, the impacts of HONI rate changes must also be considered when rates are reset.

Monthly results from 2007 through to September 2009 have been provided which highlight a trend of over-recoveries in both Network Service and Line and Transformation Connection Services up to the end of 2008. In 2009, the over-recoveries have been reduced to more reasonable levels. This is largely due to the approach taken in Whitby Hydro's 2009 rate application which was approved by the Board for RTSRs effective May 1, 2009. In its application, Whitby Hydro proposed to forgo applying the standard UTR increases of 11.3% for Network Services and 5.5% for Line and Transformation Connection in an attempt to minimize additional over-recoveries. As a result, the RTSRs remained at the same level that was set in the prior 2008 rate year.

In the 2008 rate application, electricity distributors were also asked to propose an approach and provide the resulting RTSRs to address the UTR changes and the transmission related RSVA trends. In response, Whitby Hydro took the opportunity to prepare a detailed analysis and recommend an RTSR rate rider to the Board to minimize transmission RSVA balances at the end of the 2008 rate year. In response to submissions from Board Staff and Whitby Hydro the Board approved a rate change in line with the UTR and decided to deal with historical RSVA balances as a separate initiative. As Whitby Hydro is currently carrying significant liabilities on its balance sheet for Transmission RSVAs (account 1584 and 1586) which it wishes to minimize in line with the Board's more recent direction in this area, this application includes a request to clear these historical balances (see Exhibit 9).

ANALYSIS

The summary analysis highlights the historical trends; however, the more recent charges are key to determining the appropriate adjustments required for the existing rates, as they reflect the most up-to-date wholesale rates charged by the IESO (UTRs) and HONI. In Table 8-7, the 2009 2^{nd} half information incorporates the UTR rate changes effective July 1, 2009 as well as the HONI rate changes effective May 1, 2009. In reviewing the revenue to cost ratios for this time period, the adjustment required to move to a 1:1 ratio has been determined. Given that Whitby Hydro is also proposing a change to its TLF in this application from 1.0601 to 1.0454, an adjustment is required to factor this impact into the proposed RTSRs in order to preserve the 1:1 revenue to cost ratio as shown in the following tables.

1 **Table 8-6: Trend of Monthly Transmission Variances**

		Connection Services			Network Service		
		Retail Billings	Total Costs	Over/(Under) Recovery	Retail Billings	Total Costs	Over/(Under) Recovery
2007	Jan	402,680	342,340	60,340	466,060	404,351	61,708
	Feb	392,502	345,870	46,632	453,545	404,133	49,412
	Mar	341,086	329,831	11,255	393,923	354,322	39,601
	Apr	335,960	308,082	27,878	388,839	361,481	27,359
	May	349,460	321,439	28,021	404,785	375,030	29,756
	Jun	411,793	423,030	-11,237	476,022	494,727	-18,705
	Jul	414,394	350,536	63,858	479,373	485,164	-5,791
	Aug	442,071	417,283	24,787	511,291	501,809	9,481
	Sep	374,116	352,042	22,074	431,814	425,050	6,764
	Oct	365,196	313,729	51,468	422,541	323,415	99,126
	Nov	371,934	309,536	62,398	429,557	301,672	127,885
	Dec	398,277	336,337	61,939	460,853	346,547	114,306
2008	Jan	439,440	317,618	121,821	507,645	339,927	167,718
	Feb	354,634	318,797	35,837	409,707	349,743	59,964
	Mar	340,209	284,798	55,411	393,221	305,275	87,946
	Apr	412,918	280,015	132,903	476,706	305,841	170,865
	May	366,516	240,968	125,548	422,023	245,033	176,990
	Jun	366,392	350,692	15,700	350,369	363,938	-13,569
	Jul	502,647	355,619	147,028	502,747	369,360	133,387
	Aug	226,597	341,877	-115,280	174,543	337,146	-162,603
	Sep	380,016	333,814	46,202	375,838	343,621	32,217
	Oct	381,038	270,948	110,091	376,839	283,366	93,473
	Nov	344,378	350,344	-5,966	327,987	361,950	-33,963
	Dec	371,310	322,330	48,981	345,954	328,843	17,111
2009	Jan	417,683	327,149	90,534	400,699	356,013	44,685
	Feb	356,056	318,067	37,989	352,068	349,707	2,362
	Mar	336,336	307,842	28,494	345,401	338,562	6,839
	Apr	330,706	274,161	56,545	327,863	296,918	30,945
	May	329,008	257,379	71,629	325,197	254,322	70,875
	Jun	355,095	387,397	-32,303	352,075	420,748	-68,673
	Jul	365,895	326,069	39,825	362,784	379,381	-16,597
	Aug	414,013	462,024	-48,010	409,924	468,724	-58,800
	Sep	366,220	322,107	44,112	363,405	367,171	-3,766

1 **Table 8-7: Transmission Revenue to Cost Analysis**

Excess of Revenue over Costs (Historical and Projected)

	Actual		2009 Projection				2009
	2007	2008	Jan-Jun Act	Jul-Sep Act	Oct-Dec Fcst	Total Fcst	2nd Half
Transmission Network	540,902	729,535	87,033	-79,163	-29,598	-21,727	-108,760
Transmission Connection	449,414	718,276	252,888	35,927	95,416	384,232	131,344
	990,316	1,447,812	339,921	-43,235	65,819	362,504	22,583

Actual and Projected Revenue

	Actual		2009 Projection				2009
	2007	2008	Jan-Jun Act	Jul-Sep Act	Oct-Dec Fcst	Total Fcst	2nd Half
Transmission Network	5,318,605	4,663,578	2,103,303	1,136,113	1,079,805	4,319,221	2,215,918
Transmission Connection	4,599,468	4,486,096	2,124,883	1,146,128	1,090,337	4,361,348	2,236,465
	9,918,073	9,149,674	4,228,186	2,282,240	2,170,142	8,680,568	4,452,382

Actual and Projected Cost

	Actual		2009 Projection				2009
	2007	2008	Jan-Jun Act	Jul-Sep Act	Oct-Dec Fcst	Total Fcst	2nd Half
Transmission Network	4,777,703	3,934,043	2,016,270	1,215,275	1,109,403	4,340,948	2,324,678
Transmission Connection	4,150,055	3,767,819	1,871,995	1,110,200	994,921	3,977,116	2,105,121
	8,927,757	7,701,862	3,888,265	2,325,476	2,104,323	8,318,064	4,429,799

Revenue to Cost Ratio

	Actual		2009 Projection				2009
	2007	2008	Jan-Jun Act	Jul-Sep Act	Oct-Dec Fcst	Total Fcst	2nd Half
Transmission Network	1.11	1.19	1.04	0.93	0.97	0.99	0.95
Transmission Connection	1.11	1.19	1.14	1.03	1.1	1.1	1.06
	1.11	1.19	1.09	0.98	1.03	1.04	1.01

1 **Table 8-8: 2010 Proposed Transmission Rates**

	Current Rates	Rev to Cost Adjustment	Loss Factor Adjustment	Total Adjustment	Proposed Rates
Network					
Residential	$0.0052	4.91%	1.47%	6.38%	$0.0055
GS< 50 kW	$0.0048	4.91%	1.47%	6.38%	$0.0051
GS> 50 kW	$1.9491	4.91%		4.91%	$2.0448
USL	$0.0048	4.91%	1.47%	6.38%	$0.0051
Sentinel Lighting	$1.4774	4.91%		4.91%	$1.5499
Street Lighting	$1.4699	4.91%		4.91%	$1.5420
Line and Transformation Connection					
Residential	$0.0053	-5.87%	1.47%	-4.40%	$0.0051
GS< 50 kW	$0.0048	-5.87%	1.47%	-4.40%	$0.0046
GS> 50 kW	$1.8879	-5.87%		-5.87%	$1.7770
USL	$0.0048	-5.87%	1.47%	-4.40%	$0.0046
Sentinel Lighting	$1.4901	-5.87%		-5.87%	$1.4026
Street Lighting	$1.4595	-5.87%		-5.87%	$1.3738

LOW VOLTAGE CHARGES

OVERVIEW

As an electricity distributor that is partially embedded within Hydro One Networks (HONI), Whitby Hydro is subject to HONI's Board approved low voltage (LV) charges. As part of Whitby Hydro's 2006 rate application, the Board approved a LV rate recovery amount which is bundled into its volumetric distribution rates. The current guidelines issued by the Board through the Accounting Procedures Handbook's Frequently Asked Questions (FAQs) identifies that LV costs and approved LV recoveries be treated similar to other "pass through" charges. In line with this guidance, Whitby Hydro has tracked LV related transactions through the appropriate accounts for revenue (4075) and costs (4750) and recorded any resulting variances (in account 1550).

FORECAST OF LV COSTS

In order to determine appropriate 2010 LV recovery rates, it is necessary to review the list of currently approved charges from HONI which are applicable to Whitby Hydro's embedded location for inclusion in its LV charges. During 2009, the Board approved rates for a new Sub-Transmission (ST) rate class for HONI's customers effective May 1, 2008 with an implementation date of February 1, 2009. The new ST rate schedule effectively unbundled the components of the previous LV charges. Where previously, a single rate per kW was charged by meter delivery point, the new unbundled rates include a variety of fixed and several variable rates which are applied based on a distributor's individual structure. In addition, the Board also approved revisions to HONI's rates effective May 1, 2009 for consumption starting June 1, 2009. This approval also included credit rate riders that will be in effect from February 2009 to April 2011.

Table 8-9 below highlights the recently approved HONI rates that are currently charged to LV costs and are applicable to Whitby Hydro.

Table 8-9: HONI Rates – LV Charges Applicable to Whitby Hydro

Component	Charge Determinant per Billing Month	Rate prior to 2009	New Rate	Rate Rider #4	Rate Riders #5c & 5d	Net Rate
Service Charge	$/Delivery Point	n/a	$183.92	-$65.78	$0.13	$118.27
Common ST Lines Charge	$/kW	$0.63	$0.55	-$0.20	$0.00	$0.35
Reg Asset 2008 (RAR3a)	$/kW	n/a	-$0.01			-$0.01

	Effective	Implementation	Sunset
RAR3a	1-May-08	1-Feb-09	30-Apr-11
Rate Rider#4	1-May-08	1-Feb-09	30-Apr-11
Rate Rider#5	1-May-09	1-Jun-09	31-Aug-10

The RAR3a has been charged to account 4750 since its implementation date of February 1, 2009. While this credit could be allocated amongst other deferral accounts, Whitby Hydro plans to continue with its current practice until the sunset date as the associated dollar value is considered immaterial (less than $4K per year).

In order to determine an LV recovery rate which will be appropriate for not only the 2010 rate year, but also the subsequent 3 year IRM period, it is necessary to look at the impact of the new rates and associated rate riders that would apply over the course of the entire 4 year period. This is especially important since the duration of the listed RAR and rate riders (see above notes to table 8-9) does not match the full 4 year term. As such, once the RAR and rate riders are removed, the LV charges will increase considerably. By averaging the recovery over four years, the risk of materially understating LV charges is reduced and the combined impact of the rate riders and LV charges remains stable over the IRM period.

Whitby Hydro has taken a forecast based on existing loads (2009) and projected the LV charges based on the rates currently identified for the relevant time period to calculate the 2010 – 2013 rate years' LV charges. The total forecast is then divided by 4 years to come up with an annual average. The calculation can be seen below:

Forecast for 2010 LV Charge (and subsequent IRM term)

	2010	2011	2012	2013
Service Charge	5,677	7,780	8,828	8,828
Common ST line	142,130	195,799	223,348	223,348
RAR3a	(1,377)	0	0	0
	146,430	203,579	232,176	232,176
4 year average				203,590

LV RECOVERY RATE CALCULATION

Whitby Hydro has utilized an approach to allocate forecasted LV Charges in this application similar to the approach taken in the 2006 EDR Model. The proposed allocation of the charges is based on each class's proportion of the transmission connection amounts. These amounts are then allocated based on Whitby Hydro's 2010 load and consumption forecast. The calculations and resulting LV recovery rates are displayed in Table 8-10 and 8-11 below:

Table 8-10: Allocation of 2010 LV Charges to Rate Classes

Customer Class Name	Test Year Revenues [6] Transmission - Connection	Class Share	Low Voltage Charges [7]
Residential	1,868,210	46.8%	95,268
General Service Less Than 50 kW	361,386	9.1%	18,429
General Service 50 to 4,999 kW	1,717,168	43.0%	87,566
Unmetered Scattered Load	11,992	0.3%	612
Sentinel Lighting	168	0.0%	9
Street Lighting	33,467	0.8%	1,707
TOTAL	**3,992,393**	**100.0%**	**203,590**

Table 8-11: Calculation of 2010 LV Recovery Rates

Customer Class Name		LV Charges Allocated	Forecast Volumes (kW or kWh)	LV Recovery Rate
Residential		95,268	350,407,180	0.0003
General Service Less Than 50 kW		18,429	75,150,446	0.0002
General Service 50 to 4,999 kW		87,566	966,330	0.0906
Unmetered Scattered Load		612	2,493,809	0.0002
Sentinel Lighting		9	120	0.0715
Street Lighting		1,707	24,361	0.0701
TOTAL		203,590		

Whitby Hydro is proposing to reset the LV cost recovery portion of the distribution rates at levels which are significantly below those currently embedded in the approved distribution rates. The reduction is due to a decline in projected LV costs that can be explained by changes in how HONI has set rates for a new Sub-Transmission rate class. In addition, there has been a reduction of loading on facilities which are partially embedded within HONI which also contributes to lower expected LV costs. A comparison of the proposed recovery rates to the currently approved recoveries is shown in Table 8-12.

1 **Table 8-12: LV Recovery Rate Comparison**

Customer Class Name		2009 Board Approved Rates	2010 Proposed Rates	% Change
Residential	/kWh	0.0006	0.0003	-50.0%
General Service Less Than 50 kW	/kWh	0.0006	0.0002	-66.7%
General Service 50 to 4,999 kW	/kW	0.2297	0.0906	-60.6%
Unmetered Scattered Load	/kWh	0.0006	0.0002	-66.7%
Sentinel Lighting	/kW	0.2080	0.0715	-65.6%
Street Lighting	/kW	0.1820	0.0701	-61.5%

LOSS FACTOR

Whitby Hydro is a partially embedded distributor within Hydro One Networks' (HONI) service area and has several delivery points of electricity supply. Whitby Hydro has not been asked to complete a loss study as a result of any previous decisions. Consequently, Whitby Hydro has taken an approach consistent with the Board's Filing Requirements to prepare its loss factor estimates for the 2010 test year.

SUPPLY FACILITY LOSS FACTOR

Whitby Hydro's supply facilities loss factor (SFLF) is calculated based on the weighted average of losses applied at each delivery point by the supplier (HONI or IESO). The SFLF varies depending on the location of the delivery point and is either 0.6% or 3.4% for HONI or an average of approximately 0.3% for the IESO delivery points.

As per the Board's filing requirements, Whitby Hydro has completed schedule 2-Q (Table 8-13) using the previous 3 years worth of historical data. The 3 year period has been chosen as it represents a more accurate reflection of the supply loss situation going forward. The supply losses during the period of 2006 – 2008 shifted compared to earlier years due to the following:

- Impact of the station total meter and IT de-registration and replacement with individual feeder meters and new ITs in 2005.
- Changes in SFLFs for embedded meters during 2005 (from 0% to either 0.6% or 3.4% depending on feeder).
- Additional feeder capacity on the IESO connections and resulting changes to the load balancing between the IESO and HONI delivery points.

Given the differences in SFLFs between HONI and IESO, there is potential for the total weighted SFLF to be impacted going forward, if loads are shifted on a long-term basis between embedded and non-embedded locations. However, at this time, it is not anticipated that the weighting of loads by location will be adjusted in any significant manner so as to affect the SFLF.

The weighted average SFLF for the previous 3 year period is 1.00800.

DISTRIBUTION LOSSES

Whitby Hydro's distribution loss factor (DLF) is 1.0371 on average over the past 3 years which is below the 5% DLF materiality threshold outlined in the Board's Filing Requirements. The proposed DLF has not changed significantly compared to the currently approved rate of 1.0353.

TOTAL LOSS FACTOR

Whitby Hydro has calculated the total loss factor (TLF) to be applied to customers' consumption based on the average wholesale and retail kWh for the 3 historical years (2006 – 2008). As a result of this analysis, Whitby Hydro is proposing that the TLF for 2010 be set at 1.0454. This represents a 1.4% decrease from the current approved TLF of 1.0601. The calculations are summarized in Table 8-13: Loss Factors (Appendix 2-Q).

1 **Table 8-13: Loss Factors (Appendix 2-Q)**

	Loss Factors (appendix 2-Q)	2006	2007	2008	Average
	Losses in Distributor's System				
A1	"Wholesale" kWh delivered to distributor (higher value)	897,193,840	911,179,239	897,673,634	902,015,571
A2	"Wholesale" kWh delivered to distributor (lower value)	888,890,012	904,330,932	891,338,683	894,853,209
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer	888,890,012	904,330,932	891,338,683	894,853,209
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)				
D	"Retail" kWh delivered by distributor	851,919,155	867,531,513	868,996,084	862,815,584
E	Portion of "Retail" kWh delivered by distributor for Large Use Customers(s)				
F	Net "Retail" kWh delivered by distributor (D)-(E)	851,919,155	867,531,513	868,996,084	862,815,584
G	Loss Factor in distributor's system [C/F]	1.0434	1.0424	1.0257	1.0371
	Losses Upstream of Distributor's System				
H	Supply Facility Loss Factor	1.0093	1.0076	1.0071	1.0080
	Total Losses				
I	Total Loss Factor [(G) x (H)]	1.0531	1.0503	1.0330	1.0454
	Additional supply loss factor				
	Adjusted Total Loss Factor	**1.0531**	**1.0503**	**1.0330**	**1.0454**

RATE SCHEDULES AND BILL IMPACTS

PROPOSED RATES

The following table sets out Whitby Hydro's proposed 2010 distribution rates based on the design approach and calculations described in the preceding sections. The table includes distribution rates and smart meter funding adders only.

Table 8-14: 2010 Proposed Distribution Rates and Smart Meter Funding Adder

Class	Proposed MSC (excl. Smart Meter Funding Adder)	Smart Meter Funding Adder	Proposed Volumetric Distribution Charge	Per
Residential	$ 17.62	$ 2.13	$ 0.0148	kWh
GS< 50 kW	$ 20.44	$ 2.13	$ 0.0200	kWh
GS> 50 kW	$ 191.34	$ 2.13	$ 4.0566	kW
USL	$ 9.59		$ 0.0312	kWh
Sentinel Lights	$ 4.19		$ 11.3413	kW
Streetlights	$ 1.40		$ 5.6149	kW

In addition, the proposed 2010 rate schedule includes rates for

- Regulatory Asset Recovery Rate Rider – as described in Exhibit 9
- Lost Revenue (LRAM) Rate Rider – as described in Exhibit 10
- Transmission Service - as described earlier in this Exhibit
- Wholesale Market Service and Rural Rate Protection - based on the most current rates announced by the OEB at the time of this filing
- Standard Supply Service – shown at existing rates
- Specific Service Charges – as outlined in Exhibit 3 all existing rates are proposed to continue with one new rate added for Legal Letters
- Retail Service Charges – no change proposed from existing rates
- Allowance – no change proposed from existing rates for:
  - Transformer Ownership
  - Primary Metering
- Loss Factors – details as provided earlier in this Exhibit

These rates are reflected in the proposed 2010 rate schedule included as Table 8-15.

BILLING DETERMINANTS FOR STREETLIGHTS AND SENTINEL LIGHT CLASSES

In the past, Streetlight and Sentinel light customer classes were generally billed monthly service charges based on the number of lights. Whitby Hydro's monthly service charge rates have always been developed on this basis. In light of this, Whitby Hydro's responses to data requests for "connection" counts for these classes have always been submitted using the number of lights as the base, since that was what formed the underlying billing determinant for the revenue generated.

While this may be a commonly used practice, Whitby Hydro notes that the Tariff of Rates and Charges do not currently acknowledge a differentiation between connections and number of lights. Exhibit 7 details the differences and average ratios of street lights and sentinel lights to connections based on Whitby Hydro's current and proposed system structure. While connections are a more appropriate method for applying cost allocation, lights are recognized to be a more simplified approach for billing purposes. Given the different design configurations, using the number of lights for fixed rate billing allows for greater transparency and is a more recognizable basis for billing which is beneficial to the customer as well as the distributor.

Whitby Hydro proposes to continue to use this practice, however to improve clarification and acknowledge the differences between lights and connections, Whitby Hydro requests that the proposed 2010 Tariff of Rates and Charges be updated to reference the number of lights as the basis for the monthly service charge for the both Streetlight and Sentinel light classes.

Table 8-15: Proposed Tariff of Rates and Charges

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.62
Smart Meter Funding Adder	$	2.13
Distribution Volumetric Rate Rider	$/kWh	0.0148
Regulatory Asset Recovery Rate Rider	$/kWh	(0.0017)
LRAM Rate Rider	$/kWh	0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051
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	$	20.44
Smart Meter Funding Adder	$	2.13
Distribution Volumetric Rate	$/kWh	0.0200
Regulatory Asset Recovery Rate Rider	$/kWh	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
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	$	191.34
Smart Meter Funding Adder	$	2.13
Distribution Volumetric Rate	$/kW	4.0566
Regulatory Asset Recovery Rate Rider	$/kW	(0.6875)
LRAM Rate Rider	$/kW	0.0153
Retail Transmission Rate – Network Service Rate	$/kW	2.0448
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7770
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)	$	9.59
Distribution Volumetric Rate	$/kWh	0.0312
Regulatory Asset Recovery Rate Rider	$/kWh	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
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 light)	$	4.19
Distribution Volumetric Rate	$/kW	11.3413
Regulatory Asset Recovery Rate Rider	$/kW	(0.4912)
Retail Transmission Rate – Network Service Rate	$/kW	1.5499
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4026
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 light)	$	1.40
Distribution Volumetric Rate	$/kW	5.6149
Regulatory Asset Recovery Rate Rider	$/kW	(0.7408)
Retail Transmission Rate – Network Service Rate	$/kW	1.5420
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3738
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration:		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post-dated cheques	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge / change of occupancy charge	$	30.00
Returned Cheque charge (plus bank charges)	$	15.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Legal letter charge	$	15.00
Non-Payment of Account:		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00

Install / remove load control device – during regular hours	$	65.00
Install / remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

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

Retailer Service Agreement -- One time charge to establish the service agreement	$	100.00
Monthly Fixed Charge (per retailer)	$	20.00
Monthly Variable Charge (per customer, per retailer)	$/cust	0.50
Distributor-Consolidated Billing -monthly charge (per customer, per retailer)	$/cust	0.30
Retailer-Consolidated Billing -monthly credit (per customer, per retailer)	$/cust	(0.30)
Service Transaction Request -request fee (per request, applied to the requesting party)	$	0.25
Service Transaction Request -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

TLF - Secondary Metered Customer <5,000 kW	1.0454
TLF - Primary Metered Customer <5,000 kW	1.0349

BILL IMPACTS

Bill impacts have been calculated including the 2010 proposed rates for Distribution, Smart Meter funding adder, Regulatory Asset Recovery rate rider, LRAM rate rider as well as the proposed Transmission Service rates and Loss Factors. Other rates remain unchanged from those currently approved. The 2009 bills have been calculated on the basis of existing rates which currently do not include a Regulatory Asset Recovery rate rider or an LRAM rate rider.

The total bill impacts can be summarized by customer class as follows:

Residential	RPP @ 800 kWh:	1.2%
GS<50 kW	RPP @ 2,000 kWh:	0.4%
GS>50 kW	Non- RPP @ 100 kW, 40,000 kWh	(1.0)%
USL	RPP @ 500 kWh	(3.5)%
Sentinel lights	RPP @ 1 kW, 150 kWh	17.0%
Streetlights	Non-RPP @ 1kW, 150 kWh	4.6%

A more complete list of bill impact summaries has been included as Table 8-16. This table provides information for each customer class at varying levels of consumption and/or demand, and includes both dollar and percentage changes. Detail bill impacts are provided in Whitby Hydro's rate model (sheet F8 Bill Impacts) which reflect requirements outlined as part of Appendix 2-R of the Board's Filing Requirements.

Table 8-16: Bill Impact Summary

Customer Class	Volume		RPP	Distribution Charges		Delivery Sub-total		Total Bill	
	kWh	kW	Price	$ change	%change	$ change	%change	$ change	% change
Residential	100	0	Winter	$2.15	11.3%	$2.02	10.0%	$1.92	6.9%
	250	0	Winter	$2.32	11.0%	$2.01	8.4%	$1.77	4.2%
	500	0	Winter	$2.59	10.5%	$1.96	6.5%	$1.49	2.2%
	800	0	Winter	$2.92	10.2%	$1.93	5.1%	$1.18	1.2%
	1,000	0	Winter	$3.14	10.0%	$1.89	4.4%	$0.81	0.7%
	1,500	0	Winter	$3.69	9.6%	$1.81	3.3%	$0.18	0.1%
	2,000	0	Winter	$4.24	9.4%	$1.73	2.6%	($0.44)	(0.2%)
GS<50 kW	1,000	0	Non-res.	$4.96	13.2%	$3.12	6.5%	$2.04	1.6%
	2,000	0	Non-res.	$6.86	12.3%	$3.18	4.2%	$1.01	0.4%
	3,000	0	Non-res.	$8.76	11.9%	$3.24	3.1%	$0.01	0.0%
	4,000	0	Non-res.	$10.66	11.6%	$3.33	2.5%	($0.99)	(0.2%)
	5,000	0	Non-res.	$12.56	11.4%	$3.38	2.1%	($2.01)	(0.3%)
	10,000	0	Non-res.	$22.06	11.0%	$3.71	1.2%	($7.10)	(0.6%)
	15,000	0	Non-res.	$31.56	10.8%	$4.00	0.9%	($12.20)	(0.7%)
GS>50 kW	15,000	60	n/a	$42.15	10.7%	$0.91	0.1%	($14.03)	(0.8%)
	40,000	100	n/a	$69.50	13.1%	$0.76	0.1%	($39.09)	(1.0%)
	100,000	200	n/a	$137.87	15.9%	$0.39	0.0%	($99.19)	(1.0%)
	400,000	500	n/a	$342.98	18.3%	($0.72)	(0.0%)	($399.09)	(1.1%)
	750,000	1,500	n/a	$1,026.68	19.5%	($4.42)	(0.0%)	($751.36)	(1.1%)
	1,000,000	2,000	n/a	$1,368.53	19.7%	($6.27)	(0.0%)	($1,002.20)	(1.1%)
	2,500,000	3,500	n/a	$2,394.08	20.0%	($11.82)	(0.0%)	($2,501.63)	(1.1%)
USL	100	0	Non-res.	($0.51)	(3.9%)	($0.70)	(4.9%)	($0.80)	(3.7%)
	500	0	Non-res.	($1.03)	(3.9%)	($1.94)	(6.2%)	($2.41)	(3.5%)
	1,000	0	Non-res.	($1.68)	(4.0%)	($3.52)	(6.7%)	($4.60)	(3.5%)
	2,000	0	Non-res.	($2.98)	(4.0%)	($6.66)	(7.0%)	($8.83)	(3.4%)
	3,000	0	Non-res.	($4.28)	(4.0%)	($9.80)	(7.1%)	($13.03)	(3.4%)
	4,000	0	Non-res.	($5.58)	(4.0%)	($12.91)	(7.1%)	($17.23)	(3.4%)
	5,000	0	Non-res.	($6.88)	(4.0%)	($16.06)	(7.2%)	($21.45)	(3.3%)
Sentinel Lights	90	0.248	Non-res.	$2.21	46.0%	$2.08	37.5%	$2.00	16.2%
	100	0.280	Non-res.	$2.32	46.0%	$2.17	37.0%	$2.07	15.4%
	105	0.289	Non-res.	$2.35	46.0%	$2.21	37.1%	$2.11	15.2%
	150	1.000	Non-res.	$4.90	46.1%	$4.39	32.3%	$4.24	17.0%
	0	0.000	Non-res.	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
	0	0.000	Non-res.	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
	0	0.000	Non-res.	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Street Lights	50	0.177	n/a	$0.62	35.2%	$0.48	21.1%	$0.42	6.8%
	65	0.177	n/a	$0.62	35.2%	$0.48	21.1%	$0.41	5.6%
	84	0.177	n/a	$0.62	35.2%	$0.48	21.1%	$0.40	4.5%
	150	1.000	n/a	$1.84	35.7%	$1.08	13.4%	$0.92	4.6%

* Distribution Charges includes Monthly Service Charge, Smart Meter Funding Adder, and Volumetric.
** Delivery Charges includes all Distribution charges noted above plus Regulatory Asset Recovery Rate Rider LRAM Rate Rider, and Transmission Service Charges.

RATE MITIGATION

Whitby Hydro submits that the bill impacts of its proposed 2010 rates are reasonable and do not require rate mitigation.

For the Sentinel light customer class, the bill impacts are above 10% largely due to the implementation of changes to the revenue to cost ratios from the Cost Allocation Study. Whitby Hydro proposes to move this class 50% of the way towards the Board's target range with the remaining movement to occur equally over 2011 and 2012. While the resulting total bill impact is above the 10% level, it should be noted that all of Whitby Hydro's Sentinel light customers receive combined bills under either the Residential, GS<50 kW or Streetlight classes. As a result, the aggregate bill impact to a customer will be much lower that the 17% noted when combined as a regular customer bill. In addition, the dollar value of the increase (at the demand and consumption level noted in the Bill impact section) is only $4.24/month which is not considered to be a significant impact for these particular customers.

RECONCILIATION OF RATE CLASS REVENUE

The following table provides a reconciliation between the 2010 distribution rate calculations based on the 2010 proposed rates and load forecasts and the total gross base revenue requirement:

	Load Forecast		Proposed Rates				
Customer Class	**Customer Count/ Connection**	**kWh/kW**	**Fixed**	**Variable**	**Fixed Distribution Revenue**	**Variable Distribution Revenue**	**Total Distribution Revenue**
Residential	36,927	350,407,180	17.62	0.0148	7,807,845	5,186,026	12,993,871
GS<50 kW	1,909	75,150,446	20.44	0.02	468,240	1,503,009	1,971,248
GS>50 kW	435	966,330	191.34	4.0566	998,795	3,920,014	4,918,809
USL	391	2,493,809	9.59	0.0312	44,996	77,807	122,803
Sentinel Lights	37	120	4.19	11.3413	1,860	1,361	3,221
Streetlights	11,478	24,361	1.40	5.6149	192,830	136,785	329,615
Total					**9,514,566**	**10,825,002**	**20,339,568**

Gross Base Revenue Requirement (includes add back of Transformer Ownership Allowance)	20,353,606
Difference (due to rounding)	(14,038)

EXHIBIT 9
DEFERRAL AND VARIANCE ACCOUNTS

DEFERRAL AND VARIANCE ACCOUNTS

OVERVIEW:

This Exhibit provides information on the status of the deferral and variance accounts maintained by Whitby Hydro, the proposed disposition of certain account balances and the rate riders required for recovery or refund of the associated account balances.

Whitby Hydro has prepared this information in accordance with the OEB's Filing Guidelines and the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative EB-2008-0046 (EDDVAR), dated July 31, 2009.

As required, a certification by the Chief Executive Officer regarding the accounting treatment that was used by Whitby Hydro in relation to regulatory deferral and variance accounts has been provided (Attachment 9-1).

Whitby Hydro received final approval from the Board to recover its regulatory asset balances accumulated to December 31, 2004 in its 2006 EDR Application (RP-2005-0020/EB-2005-0435). In 2007, the approved balances were transferred over to account 1590 along with the interest charges incurred up to the date of the transfer. The corresponding rate riders for the recovery of the approved balances and the transferred interest expired on April 30, 2008.

The balances approved as part of the 2006 EDR are summarized as follows:

Table 9-1: Board Approved Balances

USoA	Principal - Dec 31-04	Hydro One Estimated Charges	Total	Interest - Dec 31-04	Projected Interest to Apr 30-06	Total Interest	Grand Total
1580	1,182,965	0	1,182,965	204,954	122,978	327,932	1,510,897
1582	0	0	0	0	0	0	0
1584	1,127,053	(108,605)	1,018,448	128,529	111,810	240,339	1,258,787
1586	930,664	450,065	1,380,729	103,124	93,862	196,986	1,577,715
1588	(572,377)	0	(572,377)	50,417	3,956	54,373	(518,004)
1508	0	28,671	28,671	0	0	0	28,671
1518	106,358	0	106,358	10,736	10,281	21,017	127,375
1548	21,118	0	21,118	3,436	2,041	5,477	26,595
1525	46,954	15,169	62,123	6,721	4,707	11,428	73,551
1571	1,042,583	0	1,042,583	194,784	100,783	295,567	1,338,150
1572	0	0	0	0	0	0	0
1574	0	0	0	0	0	0	0
2425	0	0	0	0	0	0	0
1570	142,660	0	142,660	26,719	13,790	40,510	183,170
	4,027,978	385,300	4,413,278	729,420	464,209	1,193,629	5,606,907

In the current proceeding, Whitby Hydro is requesting disposition of balances (as of December 31, 2008 plus interest to April 30, 2010) of all deferral and variance accounts with the exception of PILs related accounts which will be addressed once the current PILs proceeding is completed and guidance is provided by the OEB. Smart Meter variance accounts will be addressed separately from remaining accounts due to the unique nature of the variances and the separate filing detail required.

Going forward, Whitby Hydro does not request any distributor specific deferral or variance accounts, but does intend to utilize those accounts that have been (or will be) made available by the OEB for all distributors as a result of their common applicability (i.e. IFRS, Green Energy, Smart Grid etc.).

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

The deferral and variance accounts which have outstanding balances on December 31, 2008 have been identified and described below. The accounts have been divided into groupings as per the Report of the Board on EDDVAR issued July 31, 2009.

Group 1

1550 Low Voltage Variance Account

The account is used by embedded distributors to record the net difference between Low Voltage charges and the associated revenue (included in distribution rates) collected from customers.

1580 RSVA – Wholesale Market Service

This account is used to record the net difference between the amount charged by the IESO for wholesale market services and the amount billed to customers using the OEB approved wholesale market service rate.

1584 RSVA – Retail Transmission Network Charges

This account is used to record the net difference between the retail transmission network charges paid to the IESO and Hydro One and the amount billed to customers using the OEB approved transmission network rate.

1586 RSVA – Retail Transmission Connection Charges

This account is used to record the net difference between the retail transmission connection charges paid to the IESO and Hydro One and the amount billed to customers using the OEB approved transmission connection rate.

1588 RSVA – Power (excluding the Global Adjustment)

This account is used to record the net difference between the energy amount paid to the IESO for electricity and the amount billed to customers for electricity. The Global Adjustment is tracked separately in a sub-account. This account records the variance between Board approved line losses and actual line loss for the applicable period.

1588 RSVA – Power (Sub-Account) Global Adjustment

This account is used to record the net difference between the global adjustment charged for non-RPP consumption and the provincial benefit billed to non-RPP customers.

1590 Recovery of Regulatory Asset Balances

This account includes the net difference between the regulatory asset and liability balances authorized by the Board for recovery in rates from the 2006 EDR Application and the amounts billed to customer through the OEB approved rate rider.

Group 2

1518 RCVA Retail

This account is used to record the difference between the revenue collected from retailers for retail settlement activities and the actual costs associated with providing retail services.

1525 Miscellaneous and Deferred Debits

This account includes incremental costs related to the Ontario Price Credit (OPC) rebate cheque program for electricity customers.

1548 RCVA – Service Transaction Request

This account is used to record the difference between the amount billed in relation to a STR and the incremental cost of providing these services.

1555 Smart Meter Capital and Recovery Offset

This account records the net difference between the amounts paid by Whitby Hydro for smart meter implementation (capital investments including a return on invested capital and capitalized direct costs related to the smart meter program) and the amounts charged to customers by way of the OEB approved smart meter rate rider (funding adder).

1562 Deferred PILs

This account records the amount resulting from the OEB approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent years.

1563 Contra Account – Deferred PILs

Amounts recorded in this account are applicable to a distributor using the third accounting method approved for recording entries in account 1562 in accordance with the Board's accounting instructions for PILs as set out in the April 2003 Frequently Asked Questions on the Accounting Procedures Handbook. The offsetting entry of each entry in account 1562 shall be made to the contra account.

Whitby Hydro is not aware of any exceptions to the use of the above accounts which would deviate from the intentions described in the Accounting Procedures Handbook (APH).

Account Specific Filing Requirements

RSVA Accounts (1580/1584/1586/1588)

On a historical basis, Whitby Hydro used a "hybrid" approach to the calculation of deferral and variance account balances whereby the principal balance is reported on an accrual basis, while interest charges are calculated using a cash basis. At the time of adoption, Whitby Hydro believed that this was the most meaningful method to report balances and that this approach conformed to Article 490 of the APH. Subsequent to recent revisions of Article 490, it became apparent that distributors are now required to use a full cash basis approach or a full accrual basis approach, rather than a hybrid of the two. After discussing the reporting requirements with Board Staff, Whitby Hydro recalculated all of its interest charges for transactions and account balances that had not already been approved for disposition (i.e. balances associated with transactions occurring after December 31, 2004) using the accrual basis. The timeline was selected to avoid altering balances and rate riders which were previously approved for recovery as part of Whitby Hydro's 2006 EDR. The results of the interest recalculation using the accrual basis have been included in the account balances reported in Table 9-2.

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

Proposed Disposition

Whitby Hydro is seeking disposition of the following accounts/balances:

Table 9-2: Proposed Balances for Disposition

	Balances at December 31, 2008			Projected Interest to Apr 30,2010	Total for Disposition
	Principal	Interest	Total		
1518-RCVARetail	212,626	19,874	232,500	2,808	235,308
1525-Miscellaneous Deferred Debits	1,168	162	1,330	15	1,345
1548-RCVASTR	(1,104)	(39)	(1,143)	(15)	(1,158)
1550-LV Variance Account	(65,517)	(3,890)	(69,407)	(865)	(70,272)
1580-RSVAWMS	(2,028,638)	(67,538)	(2,096,176)	(26,794)	(2,122,970)
1584-RSVANW	(1,265,631)	(35,302)	(1,300,933)	(16,716)	(1,317,649)
1586-RSVACN	(1,318,056)	(49,652)	(1,367,708)	(17,409)	(1,385,117)
1588-RSVAPOWER	(999,440)	28,337	(971,103)	(13,201)	(984,304)
1588-RSVAPOWER -Global Adjust	464,290	(3,882)	460,408	6,132	466,540
Subtotal	**(5,000,302)**	**(111,930)**	**(5,112,232)**	**(66,044)**	**(5,178,276)**
1590-Recovery of Reg Assets	(1,453,107)	973,744	(479,363)	(19,193)	(498,556)
Total	**(6,453,409)**	**861,814**	**(5,591,595)**	**(85,237)**	**(5,676,832)**

These balances reflect information up to the last audited fiscal year December 31, 2008 plus interest charges estimated up to April 30, 2010.

A single rate rider is proposed for each rate class which in aggregate will recover the total net balances from the above accounts. PILs Variance Accounts are not included as disposition of their balances will be deferred until such time as the PILs initiative has been completed and further direction is provided by the OEB. Smart Meter Variance account (1555) has also been excluded as the costs associated with the installation and implementation of Smart Meters will be addressed in a separate section.

A continuity schedule for the period of January 1, 2005 to the end of December 31, 2008 including estimated interest charges up to the April 30, 2010 has been included in Table 9-3.

Table 9-3: Continuity Schedule – Deferral and Variance Accounts

B5 Deferral / Variance Account Balances

Interest Rate (from sheet Y1) = 0.99%				1-Jan-2005 to 31-Dec-2005			
Deferral / Variance Account	**Rates**	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1518-RCVARetail	6	106,358	51,993	158,351	10,736	9,192	19,928
1525-Miscellaneous Deferred Debits	6	46,954		46,954	6,721	3,404	10,125
1548-RCVASTR	6	21,118	454	21,572	3,436	1,545	4,981
1550-LV Variance Account	6						
1555-Smart Meters Capital Variance Account	6						
1562-Deferred Payments in Lieu of Taxes	6	(667,298)	(716,967)	(1,384,265)	46,823	(65,089)	(18,266)
1563-Account 1563 - Deferred PILs Contra Account	6	667,298	716,967	1,384,265	(46,823)	65,089	18,266
1565-Conservation and Demand Management Expenditures and Recoveries	6	99,377	(899,421)	(800,044)			
1566-CDM Contra Account	6	(99,377)	899,421	800,044			
1570-Qualifying Transition Costs	6	158,511	(15,851)	142,660	29,688	7,374	37,062
1571-Pre-market Opening Energy Variance	6	1,042,583		1,042,583	194,784	75,587	270,371
1574-1588 RSVA Global Adjustment	6		(428,022)	(428,022)		(9,045)	(9,045)
1580-RSVAWMS	6	1,182,965	796,936	1,979,901	204,954	105,968	310,922
1584-RSVANW	6	1,127,053	157,356	1,284,409	128,529	47,701	176,230
1586-RSVACN	6	930,664	137,409	1,068,073	103,124	38,590	141,714
1588-RSVAPOWER	6	(572,377)	647,665	75,288	50,417	25,593	76,010
TOTAL	**6**	**4,043,829**	**1,347,940**	**5,391,769**	**732,389**	**305,909**	**1,038,298**

Interest Rate (from sheet Y1) = 0.99%				1-Jan-2006 to 31-Dec-2006			
Deferral / Variance Account	**Rates**	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1518-RCVARetail	6	158,351	74,589	232,940	19,928	10,058	29,986
1525-Miscellaneous Deferred Debits	6	46,954	1,168	48,122	10,125	2,536	12,661
1548-RCVASTR	6	21,572	(360)	21,212	4,981	1,159	6,140
1550-LV Variance Account	6		11,631	11,631		(569)	(569)
1555-Smart Meters Capital Variance Account	6		(82,216)	(82,216)		(695)	(695)
1562-Deferred Payments in Lieu of Taxes	6	(1,384,265)	(42,449)	(1,426,714)	(18,266)	(71,119)	(89,385)
1563-Account 1563 - Deferred PILs Contra Account	6	1,384,265	42,449	1,426,714	18,266	71,119	89,385
1565-Conservation and Demand Management Expenditures and Recoveries	6	(800,044)	252,624	(547,420)			
1566-CDM Contra Account	6	800,044	(252,624)	547,420			
1570-Qualifying Transition Costs	6	142,660		142,660	37,062	7,706	44,768
1571-Pre-market Opening Energy Variance	6	1,042,583		1,042,583	270,371	56,317	326,688
1574-1588 RSVA Global Adjustment	6	(428,022)	590,447	162,425	(9,045)	(261)	(9,306)
1580-RSVAWMS	6	1,979,901	(1,084,661)	895,240	310,922	93,328	404,250
1584-RSVANW	6	1,284,409	(152,550)	1,131,859	176,230	65,124	241,354
1586-RSVACN	6	1,068,073	(115,000)	953,073	141,714	53,721	195,435
1588-RSVAPOWER	6	75,288	77,042	152,330	76,010	38,648	114,658
TOTAL	**6**	**5,391,769**	**(679,910)**	**4,711,859**	**1,038,298**	**327,072**	**1,365,370**

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Interest Rate (from sheet Y1) = 0.99%				1-Jan-2007 to 31-Dec-2007			
Deferral / Variance Account	**Rates**	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1518-RCVARetail	6	232,940	(51,448)	181,492	29,986	(17,225)	12,761
1525-Miscellaneous Deferred Debits	6	48,122	(46,954)	1,168	12,661	(12,606)	55
1548-RCVASTR	6	21,212	(22,066)	(854)	6,140	(6,123)	17
1550-LV Variance Account	6	11,631	(73,130)	(61,499)	(569)	(2,310)	(2,879)
1555-Smart Meters Capital Variance Account	6	(82,216)	(50,620)	(132,836)	(695)	(5,365)	(6,060)
1562-Deferred Payments in Lieu of Taxes	6	(1,426,714)		(1,426,714)	(89,385)	(63,627)	(153,012)
1563-Account 1563 - Deferred PILs Contra Account	6	1,426,714		1,426,714	89,385	63,627	153,012
1565-Conservation and Demand Management Expenditures and Recoveries	6	(547,420)	547,420				
1566-CDM Contra Account	6	547,420	(547,420)				
1570-Qualifying Transition Costs	6	142,660	(142,660)		44,768	(44,768)	
1571-Pre-market Opening Energy Variance	6	1,042,583	(1,042,583)		326,688	(326,688)	
1574-1588 RSVA Global Adjustment	6	162,425	(34,665)	127,760	(9,306)	(2,019)	(11,325)
1580-RSVAWMS	6	895,240	(2,333,179)	(1,437,939)	404,250	(400,667)	3,583
1584-RSVANW	6	1,131,859	(1,667,955)	(536,096)	241,354	(207,152)	34,202
1586-RSVACN	6	953,073	(1,552,853)	(599,780)	195,435	(180,893)	14,542
1588-RSVAPOWER	6	152,330	(58,240)	94,090	114,658	(60,389)	54,269
TOTAL	**6**	**4,711,859**	**(7,076,353)**	**(2,364,494)**	**1,365,370**	**(1,266,205)**	**99,165**

Interest Rate (from sheet Y1) = 0.99%				1-Jan-2008 to 31-Dec-2008			
Deferral / Variance Account	**Rates**	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1518-RCVARetail	6	181,492	31,134	212,626	12,761	7,113	19,874
1525-Miscellaneous Deferred Debits	6	1,168		1,168	55	107	162
1548-RCVASTR	6	(854)	(250)	(1,104)	17	(56)	(39)
1550-LV Variance Account	6	(61,499)	(4,018)	(65,517)	(2,879)	(1,011)	(3,890)
1555-Smart Meters Capital Variance Account	6	(132,836)	400,176	267,340	(6,060)	(5,957)	(12,017)
1562-Deferred Payments in Lieu of Taxes	6	(1,426,714)		(1,426,714)	(153,012)	(53,571)	(206,583)
1563-Account 1563 - Deferred PILs Contra Account	6	1,426,714		1,426,714	153,012	53,571	206,583
1565-Conservation and Demand Management Expenditures and Recoveries	6						
1566-CDM Contra Account	6						
1570-Qualifying Transition Costs	6						
1571-Pre-market Opening Energy Variance	6						
1574-1588 RSVA Global Adjustment	6	127,760	336,530	464,290	(11,325)	7,443	(3,882)
1580-RSVAWMS	6	(1,437,939)	(590,699)	(2,028,638)	3,583	(71,121)	(67,538)
1584-RSVANW	6	(536,096)	(729,535)	(1,265,631)	34,202	(69,504)	(35,302)
1586-RSVACN	6	(599,780)	(718,276)	(1,318,056)	14,542	(64,194)	(49,652)
1588-RSVAPOWER	6	94,090	(1,093,530)	(999,440)	54,269	(25,932)	28,337
TOTAL	**6**	**(2,364,494)**	**(2,368,468)**	**(4,732,962)**	**99,165**	**(223,112)**	**(123,947)**

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Interest Rate (from sheet Y1) = 0.99%		31-Dec-2008 Balance			1-Jan-09 to 30-Apr-09		
Deferral / Variance Account	**Rates**	**Principal**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1518-RCVARetail	6	212,626	19,874	232,500	702		233,202
1525-Miscellaneous Deferred Debits	6	1,168	162	1,330	4		1,334
1548-RCVASTR	6	(1,104)	(39)	(1,143)	(4)		(1,147)
1550-LV Variance Account	6	(65,517)	(3,890)	(69,407)	(216)		(69,623)
1555-Smart Meters Capital Variance Account	6	267,340	(12,017)	255,323	883		256,206
1562-Deferred Payments in Lieu of Taxes	6	(1,426,714)	(206,583)	(1,633,297)	(4,711)		(1,638,008)
1563-Account 1563 - Deferred PILs Contra Account	6	1,426,714	206,583	1,633,297	4,711		1,638,008
1565-Conservation and Demand Management Expenditures and Recoveries	6						
1566-CDM Contra Account	6						
1570-Qualifying Transition Costs	6						
1571-Pre-market Opening Energy Variance	6						
1574-1588 RSVA Global Adjustment	6	464,290	(3,882)	460,408	1,533		461,941
1580-RSVAWMS	6	(2,028,638)	(67,538)	(2,096,176)	(6,699)		(2,102,875)
1584-RSVANW	6	(1,265,631)	(35,302)	(1,300,933)	(4,179)		(1,305,112)
1586-RSVACN	6	(1,318,056)	(49,652)	(1,367,708)	(4,352)		(1,372,060)
1588-RSVAPOWER	6	(999,440)	28,337	(971,103)	(3,300)		(974,403)
TOTAL	**6**	**(4,732,962)**	**(123,947)**	**(4,856,909)**	**(15,628)**	**0**	**(4,872,537)**

				con't...
Interest Rate (from sheet Y1) = 0.99%		1-May-09 to 31-Dec-09		
Deferral / Variance Account	**Rates**	**Interest**	**Other**	**Balance**
1518-RCVARetail	6	1,404		234,606
1525-Miscellaneous Deferred Debits	6	8		1,342
1548-RCVASTR	6	(7)		(1,154)
1550-LV Variance Account	6	(433)		(70,056)
1555-Smart Meters Capital Variance Account	6	1,766		257,971
1562-Deferred Payments in Lieu of Taxes	6	(9,422)		(1,647,430)
1563-Account 1563 - Deferred PILs Contra Account	6	9,422		1,647,430
1565-Conservation and Demand Management Expenditures and Recoveries	6			
1566-CDM Contra Account	6			
1570-Qualifying Transition Costs	6			
1571-Pre-market Opening Energy Variance	6			
1574-1588 RSVA Global Adjustment	6	3,066		465,007
1580-RSVAWMS	6	(13,397)		(2,116,272)
1584-RSVANW	6	(8,358)		(1,313,470)
1586-RSVACN	6	(8,704)		(1,380,765)
1588-RSVAPOWER	6	(6,600)		(981,003)
TOTAL	**6**	**(31,256)**	**0**	**(4,903,794)**

							con't...
Interest Rate (from sheet Y1) = 0.99%		1-Jan-10 to 30-Apr-10		31-Dec-08 Balance + Interest to 30-Apr-10			
Deferral / Variance Account	**Rates**	**Interest**	**Other**	**Balance**	**31-Dec-08**	**Interest**	**Total**
1518-RCVARetail	6	702		235,308	232,500	2,808	235,308
1525-Miscellaneous Deferred Debits	6	4		1,345	1,330	15	1,345
1548-RCVASTR	6	(4)		(1,158)	(1,143)	(15)	(1,158)
1550-LV Variance Account	6	(216)		(70,272)	(69,407)	(865)	(70,272)
1555-Smart Meters Capital Variance Account	6	883		258,854	255,323	3,531	258,854
1562-Deferred Payments in Lieu of Taxes	6	(4,711)		(1,652,141)	(1,633,297)	(18,844)	(1,652,141)
1563-Account 1563 - Deferred PILs Contra Account	6	4,711		1,652,141	1,633,297	18,844	1,652,141
1565-Conservation and Demand Management Expenditures and Recoveries	6						
1566-CDM Contra Account	6						
1570-Qualifying Transition Costs	6						
1571-Pre-market Opening Energy Variance	6						
1574-1588 RSVA Global Adjustment	6	1,533		466,540	460,408	6,132	466,540
1580-RSVAWMS	6	(6,699)		(2,122,970)	(2,096,176)	(26,794)	(2,122,970)
1584-RSVANW	6	(4,179)		(1,317,649)	(1,300,933)	(16,716)	(1,317,649)
1586-RSVACN	6	(4,352)		(1,385,117)	(1,367,708)	(17,409)	(1,385,117)
1588-RSVAPOWER	6	(3,300)		(984,304)	(971,103)	(13,201)	(984,304)
TOTAL	**6**	**(15,628)**	**0**	**(4,919,422)**	**(4,856,909)**	**(62,513)**	**(4,919,422)**

The opening balances for the continuity schedule match those submitted for the period ending December 31, 2004 in the 2006 EDR application and subsequent year end balances tie to the most recent trial balances reported through the Electricity Reporting and Record Keeping Requirements (RRR).

In addition to the continuity schedule, a reconciliation of the 2008 regulatory trial balance (as reported through RRR) to the audited financial statements has been included (see Exhibit 1). Whitby Hydro treats regulatory assets/liabilities (as defined by the OEB and later recovered through rates) as expenses/revenue in the year incurred/billed. Regulatory assets and regulatory liabilities are disclosed in the notes to the financial statements each year.

Rates used to calculate interest amounts reflect the prescribed interest rates applicable to the approved regulatory accounts of Electricity Distributors as published on the OEB's website. Estimates for future interest rates reflect the last published rate at the time of this filing. The following table (Table 9-4) outlines the rates used by quarter:

Table 9-4: Interest Rates by Quarter

2005	Q1	7.25%
	Q2	7.25%
	Q3	7.25%
	Q4	7.25%
2006	Q1	7.25%
	Q2	4.14%
	Q3	4.59%
	Q4	4.59%
2007	Q1	4.59%
	Q2	4.59%
	Q3	4.59%
	Q4	5.14%
2008	Q1	5.14%
	Q2	4.08%
	Q3	3.35%
	Q4	3.35%
2009	Q1	2.45%
	Q2	1.00%
	Q3	0.55%
	Q4	0.55%
2010	Q1	0.55%
	April	0.55%

For the purposes of modeling, a weighted average annual interest rate was utilized for interest calculations from Jan 1, 2009 – April 30, 2010 (based on December 31, 2008 principal balances and quarterly interest rates outlined above).

Allocation to Customer Classes

Table 9-5 outlines the methodology used for allocation of balances to customer classes for each account. The allocators are consistent with the Report of the Board (EDDVAR) issued July 31, 2009.

Table 9-5: Account Allocators

Account Description	Allocation to Customer Classes
1518-RCVARetail	# of Customers
1525-Miscellaneous Deferred Debits	# of Customers - Ont Price Credit rebate cheques
1548-RCVASTR	# of Customers
1550-LV Variance Account	kWh
1580-RSVAWMS	kWh
1584-RSVANW	kWh
1586-RSVACN	kWh
1588-RSVAPOWER (excluding GA)	kWh
1588-RSVAPOWER (GA)	kWh for non-RPP customers
1590-Recovery of Reg Assets	In proportion to the recovery share as established when rate riders were implemented (2006 EDR)

As there is no 2010 consumption forecast specifically for non-RPP customers, account 1588RSVA Power (GA) has been allocated using historical (2005 – 2008) kWh for non-RPP customers as a proxy.

1588 RSVA Power - Global Adjustment (GA)

In keeping with the Board's EDDVAR report, Whitby Hydro has used kWh for non-RPP customers as an allocator for 1588 subaccount for Global Adjustment. Although the Board did not specifically address whether a separate rate rider is required for this variance account in order to recover it only from non-RPP customers, Whitby Hydro did give this approach some consideration. The two options reviewed, both follow the Board's EDDVAR report in terms of the recommended allocator to use, however the differences are in the development of the rate rider which can be described as follows:

1) Option 1 – the GA variance in each customer class is combined with other deferral/variance accounts for which disposition is requested. The total combined balance by each customer class is then used to determine a single rate rider per customer class which will be applied to all customers.

2) Option 2 – the GA variance is kept separate from other deferral/variance accounts for which disposition is being requested. A unique rate rider is then developed based on the forecasted volumes associated with non-RPP customers only. This unique rate rider would then be applicable to non-RPP customers only.

In reviewing both options, Whitby Hydro felt the key considerations should be: ability/cost to implement; the materiality of impact to RPP customers; and the consistency of the approach.

The first consideration was the ability/cost to implement the approach. Option 1 is consistent with methodologies used in the past for regulatory asset rate riders and as such, there are no implementation concerns. Whitby Hydro has done preliminary inquiries regarding option 2 and while there may be additional costs for design and set up in the CIS system, it does not appear that option 2 would be restricted by any CIS system limitations.

Once it was determined that both options are feasible from a CIS system perspective, the materiality of the impact to RPP customers was considered. An analysis of the allocator determined the vast majority (91.6%) of the non-RPP kWh (from 2005-2008) could be attributed to the GS> 50 kW customer class. As a result, much smaller shares would be allocated to Residential (5.7%), GS<50 kW (1.9%), Street lighting (0.9%), and Sentinel light (0.001%) classes, while the USL class had no non-RPP customers. Once the allocated dollar amount was split by customer class, the impact would be spread over a proposed four year recovery period. Given the kWh volumes in the Residential and GS<50 kW class and the low percentage allocated to Sentinel Lights, the impact to a customer's bill for those classes would be negligible (approximately 1 – 6 cents per month). As the Street lighting class represents only one customer, the impact is more significant. However, this customer has been a non-RPP customer for approximately one half of the time period which generated the variance and there are no intra-class subsidy concerns. For the GS>50 kW class it was determined that in 2008 approximate 85% of the class's total consumption came from non-RPP customers. As a result, a large majority of the class would receive a rate rider impact regardless of which option was selected. The impact on RPP customers in this class is not material (~0.2% of the total bill). Whitby Hydro also understands that it is not possible to develop a "perfect" option which analyzes and charges each customer in a manner that fully matches the contribution by the customer to the variance. There is continual movement of customers between RPP and non-RPP plans and as such, there is no perfect solution regardless of the option selected. With this in mind and in light of the analysis undertaken, Whitby Hydro does not believe either option would cause significant "fairness" concerns to existing RPP customers that would be material in nature.

Finally, consistency of the rate rider methodology was considered. Option 1 follows the typical approach used for group 1 deferral/variance accounts. While Whitby Hydro is not aware of how all other distributors requested recovery of balances in this variance account, it is not unreasonable to assume that most would select an approach consistent with what has been used in the past (i.e. 2006 EDR), given no specific direction suggesting otherwise was included in the Board's EDDVAR report . Also, it appears that the model developed by the Board for 2010 IRM filers has taken an approach consistent with option 1. While option 2 makes an attempt to develop a more direct cost allocation, there is some concern if customers are not treated consistently across the province.

As a result of the overall analysis, Whitby Hydro has selected option 1 to develop the rate rider for the 1588 Global Adjustment variance. Whitby Hydro suggests that with no apparent material negative impact to RPP customers, option 1 is the preferred approach as it conforms to the Boards EDDVAR and is believed to provide a consistent approach to customers when compared to historical methodologies as well as to customers across the province.

Proposed Rate Riders

In the Report of the Board (EDDVAR), the Board states that at the time of rebasing, all account balances should be disposed of unless otherwise justified. The Board also states that a volumetric rate rider should be used and that the recommended recovery period is one year. However, the Board acknowledges that a distributor can propose a different disposition period to mitigate rate impacts or address any other applicable considerations where appropriate.

Consistent with the Board's guidance, Whitby Hydro proposes to dispose of the balances in the identified accounts through a single volumetric rate rider for each customer class. In light of the significant net balance, Whitby Hydro proposes a four year recovery period. The rationale for proposing a longer recovery period is that a one year disposition of the total credit of $5.7M would create a significant rate distortion for customers both at the onset of the rate rider and upon its discontinuance. By using a four year recovery period, the rate impact is smoothed out over a time period that matches the period during which the balances accumulated.

The customer allocator and related rate rider calculations are shown in Table 9-6.

Table 9-6: Rate Rider Calculation

RateMaker 2009 release 1.1 © Elenchus Research Associates								
Whitby Hydro Electric Corporation (ED-2002-0571)								
2010 EDR Application (EB-2009-0274) version: v1.1								
November 30, 2009								
C7 Rate Riders								
Allocate recoveries of deferral / variance account balances								

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
1518-RCVARetail	235,308	Customer Count	220,567	11,403	2,598	561	173	6
1525-Miscellaneous Deferred Debits	1,345	Customer Count - OPC Rebate Cheques	1,248	93	3	1	0	0
1548-RCVASTR	(1,158)	Customer Count	(1,085)	(56)	(13)	(3)	(1)	(0)
1550-LV Variance Account	(70,272)	kWh's	(28,910)	(6,200)	(34,202)	(206)	(4)	(750)
1574-1588 RSVA Global Adjustment	466,540	kWh - non RPP customers	26,467	8,837	427,126	0	4	4,106
1580-RSVAWMS	(2,122,970)	kWh's	(873,400)	(187,315)	(1,033,272)	(6,216)	(108)	(22,659)
1584-RSVANW	(1,317,649)	kWh's	(542,087)	(116,259)	(641,314)	(3,858)	(67)	(14,064)
1586-RSVACN	(1,385,117)	kWh's	(569,844)	(122,212)	(674,151)	(4,056)	(71)	(14,784)
1588-RSVAPOWER	(984,304)	kWh's	(404,947)	(86,847)	(479,071)	(2,882)	(50)	(10,506)
Sub-Total for recovery	**(5,178,276)**		**(2,171,992)**	**(498,557)**	**(2,432,296)**	**(16,657)**	**(123)**	(58,650)
1590-Recovery of Regulatory Asset Balances (residual)	(498,553)	Per 2006 Reg Asset rate rider calculation	(215,375)	(43,392)	(225,088)	(1,052)	(113)	(13,534)
Total Recoveries Required (4 years)	**(5,676,829)**		**(2,387,367)**	**(541,948)**	**(2,657,384)**	**(17,709)**	**(236)**	(72,185)
Annual Recovery Amounts	(1,419,207)		(596,842)	(135,487)	(664,346)	(4,427)	(59)	(18,046)
Annual Volume			350,407,180	75,150,446	966,330	2,493,809	120	24,361
Proposed Rate Rider			**($0.0017)**	**($0.0018)**	**($0.6875)**	**($0.0018)**	**($0.4912)**	**($0.7408)**
per			kWh	kWh	kW	kWh	kW	kW
** per sheet C6*								

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Customers / Connections	C1	51,177	36,927	1,909	435	391	37	11,478
kWh's	C1	851,733,259	350,407,180	75,150,446	414,547,692	2,493,809	43,361	9,090,771
Distribution Revenue (existing rates)	C4	18,621,472	12,205,180	1,784,250	4,258,129	127,828	2,206	243,878
Distribution Revenue (proposed rates)	F4	19,856,446	12,913,963	1,951,368	4,537,700	122,295	3,213	327,907
Transmission Connection Revenue	C2	3,992,393	1,868,210	361,386	1,717,168	11,992	168	33,467
Customer Count	C1	39,395	36,927	1,909	435	94	29	1
Per 2006 Reg Asset rate rider calculation	2006 EDR	3,477,725	1,502,379	302,684	1,570,131	7,335	785	94,411
Customer Count - OPC Rebate Cheques	CMIC/Cognos	3,526	3,270	245	8	3		
kWh - non RPP customers	Billing System	1,492,991,890	84,698,273	28,280,598	1,366,861,881	0	12,084	13,139,054
		0						
Approved Recoveries	C5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Bill Impacts

The proposed rates and bill impacts are outlined in the table below:

Rate Class	Billing Determinant	Proposed Rate Rider	Bill Impact on Total Bill (%)
Residential	kWh	($0.0017)	-1.37%
GS< 50 kW	kWh	($0.0018)	-1.50%
GS > 50 kW	kW	($0.6875)	-1.71%
USL	kWh	($0.0018)	-1.35%
Sentinel Lighting	kW	($0.4912)	-1.68%
Streetlighting	kW	($0.7408)	-3.55%

Attachment 9-1: Certification

CERTIFICATION

I, JAMES E. LAVELLE certify that the information filed for Whitby Hydro Electric Corporation with respect to deferral and variance accounts is consistent with the accounting requirements, procedures and guidelines outlined by the Ontario Energy Board.

J. E. Lavelle

Nov. 25, 2009

James E. Lavelle
President and Chief Executive Officer

Date

SMART METER IMPLEMENTATION PLAN AND PROPOSED SMART METER RATE ADDER

On October 22, 2008, the OEB Issued Guideline G-2008-0002 “Smart Meter Funding and Cost Recovery”. The Guideline outlined filing instructions related to the funding and recovery of costs associated with smart metering activities conducted by Ontario Electricity Distributors. Based on the guidelines, Whitby Hydro qualifies as a distributor that is authorized and clearly intends to install smart meters in the test year and as such, is requesting a Utility-Specific smart meter funding adder.

Whitby Hydro is authorized as per paragraph 8 of section 1(1) of O.Reg.427/06 to conduct metering activities, and is currently in process of preparing for the mass installation of smart meters commencing in July of 2010, with a projected completion date of December of 2010.

Whitby Hydro has successfully completed negotiations with its number one ranked smart meter provider and these negotiations were undertaken in accordance with the O.Reg.235/08. A copy of the confirmation letter of the Fairness Commissioner has been included as Attachment 9-2 as evidence of procurement compliance.

Whitby Hydro has been working with a consultant on the smart meter initiative and has developed a detailed smart meter budget based on the best actual and estimated costs available. A detailed smart meter plan highlights the number of meters and installation schedule for the time period that the proposed smart meter funding adder is expected to be in effect.

While Whitby Hydro filed its base line report for smart meter installations with the Board in July of 2009, the information provided in this exhibit is Whitby Hydro’s current forecast for smart meter deployment in 2010.

Whitby Hydro did not include stranded meter costs in the rate adder calculation and will track these costs in a new sub account of 1555- Smart Meter Capital and will apply for recovery at the next rate application process when smart meters in the Whitby Hydro service area have been completely installed.

As per the Board Filing Requirements, Table 9-7 (Appendix 2-S) has been completed and included as an appendix to Exhibit 9.

SMART METER PLAN

Whitby Hydro commenced installing smart meters in January 2009 in small quantities for new residential and small commercial customers and those requiring Measurement Canada meter re-verification. It is estimated that 2,202 residential and 73 small commercial customer smart meters will be installed by the end of 2009.

Whitby Hydro has completed contract negotiations with its Advanced Metering Infrastructure (AMI) vendor and has executed the necessary contract. Pricing has also been received for the meter installation contract and it is anticipated that this contract will be executed in December 2009 for mass deployment to commence in July 2010, with all 39,028 smart meters to be installed by December 2010.

Pricing has also been received for the Operational Data Storage software with contract negotiations to be completed and contract signed by February 2010.

The Advanced Metering Regional Collectors (AMRC) were installed in December of 2008 and the systems have been operating on a test Advanced Metering Control Computer (AMCC) through 2009 to allow staff to experience real time exposure to the AMI system to gain an understanding of how the system operates. The permanent AMCC is forecasted to be installed in the first quarter of 2010. Over the course of 2010 the customer billing business process re-engineering will begin with completion targeted for December 2010.

Smart Meter Installation Schedule

	Residential				GS<50			
Month	Meters Installed	Meters Enrolled	ToU Notice Sent	ToU Billing	Meters Installed	Meters Enrolled	ToU Notice Sent	ToU Billing
May-09	198	0	0	0	62	0	0	0
Jun-09	452	0	0	0	63	0	0	0
Jul-09	792	0	0	0	65	0	0	0
Aug-09	1,132	0	0	0	66	0	0	0
Sep-09	1,382	0	0	0	67	0	0	0
Oct-09	1,729	0	0	0	71	0	0	0
Nov-09	2,104	0	0	0	73	0	0	0
Dec-09	2,202	0	0	0	73	0	0	0
Jan-10	2,238	0	0	0	73	0	0	0
Feb-10	2,274	0	0	0	73	0	0	0
Mar-10	2,310	0	0	0	73	0	0	0
Apr-10	2,346	0	0	0	73	0	0	0
May-10	2,382	0	0	0	73	0	0	0
Jun-10	2,418	0	0	0	73	0	0	0
Jul-10	8,921	0	0	0	385	0	0	0
Aug-10	15,037	0	0	0	691	0	0	0
Sep-10	22,753	0	0	0	997	0	0	0
Oct-10	28,869	0	0	0	1,303	0	0	0
Nov-10	35,305	0	0	0	1,609	0	0	0
Dec-10	37,119	0	0	0	1,909	0	0	0
Jan-11	37,155	0	37,155	0	1,909	0	1,909	0
Feb-11	37,191	0	37,191	0	1,910	0	1,910	0
Mar-11	37,227	37,227	37,227	0	1,910	1,910	1,910	0
Apr-11	37,263	37,263	37,263	0	1,910	1,910	1,910	0
May-11	37,299	37,299	37,299	0	1,910	1,910	1,910	0
Jun-11	37,335	37,335	37,335	0	1,911	1,911	1,911	0
Jul-11	37,371	37,371	37,371	37,371	1,911	1,911	1,911	1,911
Aug-11	37,407	37,407	37,407	37,407	1,912	1,912	1,912	1,912
Sep-11	37,443	37,443	37,443	37,443	1,912	1,912	1,912	1,912
Oct-11	37,479	37,479	37,479	37,479	1,913	1,913	1,913	1,913
Nov-11	37,515	37,515	37,515	37,515	1,913	1,913	1,913	1,913
Dec-11	37,544	37,544	37,544	37,544	1,914	1,914	1,914	1,914

Projected Installations To 2010			
	2009	**2010**	**Total**
Residential	2,202	34,917	37,119
GS < 50kW	73	1,836	1,909
	2,275	**36,753**	**39,028**

With the installation of all existing residential meters and small commercial customers being completed by the end of 2010, it is expected that the migration of customer data with the IESO provincial MDM/R will take place by March of 2011 with Time–of–Use billing to follow shortly after.

Therefore, costs compiled for 2009 and 2010 for the smart meter rate adder are based on actual negotiated prices as well as estimates which include incremental capital and OM&A expenses to be incurred. While it is anticipated that additional costs beyond 2010 will be incurred, the estimated cost per meter shown below reflects costs to the end of 2010 only.

Projected Cost per Meter

Total Capital Cost	$7,982,826
Total OM&A	$ 431,517
Number of Smart Meters	39,028
Capital Cost Per Smart Meter	$ 204.54
OM&A Cost Per Meter	$ 11.06
Total Cost Per Smart Meter	$ 215.60

Per Meter Cost Split	Per Meter Cost	Number of Meters	Investment	% of Investment
Smart Meter Including Installation	$ 176.90	39,028	$6,904,065	82.05%
Computer Hardware	4.76	39,028	185,850	2.21%
Computer Software	22.88	39,028	892,911	10.61%
Smart Meter Incremental Operating Expense	11.06	39,028	431,517	5.13%
Total Meter Cost Split	**$ 215.60**		**$8,414,343**	**100%**

Functionality In Excess of Minimum Functionality Adopted In O.Reg.425/06.

Whitby Hydro has not purchased nor does it anticipate purchasing any smart meters or advanced metering infrastructure (AMI) whose functionality exceeds the minimum specification provided for in O.Reg. 425/06.

Costs Associated with Replication of Smart Metering Entity SME Functionality

Whitby Hydro does not expect to incur costs associated with functions for which the SME has exclusive authority to carry out. There will be costs associated with operational data storage software which will assist Whitby Hydro in ensuring that the AMI system is operating and meeting the minimum functionality as required and to allow integration of the AMI, the IESO's provincial M/DMR and Whitby Hydro's CIS billing system.

PROPOSED SMART METER RATE ADDER

Whitby Hydro's currently approved smart meter rate adder is $1.00 per metered customer. As outlined in the following chart, Whitby Hydro has determined that to fully deploy Whitby Hydro's smart meter plan, a rate adder of $2.13 is required. Further details of the rate funding adder calculation can be found in Attachment 9-3.

Proposed Smart Meter Rate Adder	
2010 Revenue Requirement for Smart Meters	$1,004,475
2010 Forecast number of metered customers	$ 39,271
Annual revenue per metered customer	$ 25.58
Months	12.00
Proposed Rate Adder	$ 2.13

Table 9-7: Smart Meters (Appendix 2-S)

	Smart Meters Installed				Account 1555		Account 1556
Year	Residential	GS<50 kW	Other [1]	Percentage of Applicable Customers Converted (%)	Funding Adder Revenues Collected*	Capital Expenditures*	Operating Expenses*
2006	0	0	0	0.0%	82,216	0	0
2007	0	0	0	0.0%	125,648	75,028	0
2008	0	0	0	0.0%	131,297	531,472	0
2009 Fcst	2,202	73	0	5.9%	362,123	688,374	138,705
2010 Fcst	34,917	1,836	0	100.0%	827,422	6,687,952	292,812
2011 Fcst	425	5	0	100.0%	337,006	335,000	531,000

*Note a) Amounts for Account 1555 and 1556 exclude interest costs.
b) Account 1555 Forecast is based on the proposed Smart Meter rate funder from May 1, 2010 - April 30, 2011.

[1.] The distributor should provide details of Other (e.g. Toronto Hydro has some legacy non-interval GS>50 kW customers being converted to "smart" meters.

Attachment 9-2 Confirmation Letter of the Fairness Commissioner

PRP International, Inc.
Fairness Advisory Services

August 15, 2009

Mr. Jim Lavelle
President & CEO
Whitby Hydro Electric
100 Taunton Road East, Box 59
Whitby, ON L1N 5R8

Dear Mr. Lavelle:

Subject: Confirmation of the Fairness Commissioner
Whitby Hydro Electric
– 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 Whitby Hydro Electric ("WHE"), 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* WHE *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* Whitby Hydro Electric *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
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.

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.

1

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:

Whitby Hydro Electric

Mr. Jim Lavelle
President & CEO
Whitby Hydro Electric
100 Taunton Road East, Box 59
Whitby, ON L1N 5R8

[2] **Conditions on the rendering of this Confirmation / Attestation.**

- The two Negotiations Agenda were provided by WHE, via its agent Util-Assist;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between WHE and their #1 ranked Proponent;
- The successful contract award was based on the WHE 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 WHE, via its agent Util-Assist.

Attachment 9-3: Smart Meter Revenue Requirement Calculation

Sheet 1. Smart Meter Capital Cost and Operational Expense Data

Smart Meter Unit Installation Plan:

assume calendar year installation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
Planned number of Residential smart meters to be installed	-	-	-	2,202	34,917	37,119
Planned number of General Service Less Than 50 kW smart meters	-	-	-	73	1,836	1,909
Planned Meter Installation (Residential and Less Than 50 kW only)	-	-	-	2,275	36,753	39,028
Percentage of Completion	0%	0%	0%	6%	100%	

Other Unit Installation Plan:

assume calendar year installation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Tota
Planned number of Collectors to be installed			2	-	-	2
Planned number of Repeaters to be installed						-

Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE	Asset Type	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
1.1.1 Smart Meter *may include new meters and modules, etc.*	Smart Meter			$ -	$ 265,866	$ 4,706,924	$ 4,972,790
1.1.2 Installation Cost *may include socket kits plus shipping, labour, benefits, vehicle, etc.*	Smart Meter			$ -	$ 237,771	$ 1,381,338	$ 1,619,109
1.1.3a Workforce Automation Hardware *may include fieldworker handhelds, barcode hardware, etc.*	Comp. Hard.			$ -	$ 16,800	$ 22,050	$ 38,850
1.1.3b Workforce Automation Software *may include fieldworker handhelds, barcode hardware, etc.*	Comp. Soft.			$ 24,030	$ -	$ -	$ 24,030
Total Advanced Metering Communication Device (AMCD)		$ -	$ -	$ 24,030	$ 520,437	$ 6,110,313	$ 6,654,780

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	Asset Type	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
1.2.1 Collectors	Smart Meter			$ 302,400	$ -	$ -	$ 302,400
1.2.2 Repeaters *may include radio licence, etc.*	Smart Meter			$ -	$ -	$ -	$ -
1.2.3 Installation *may include meter seals and rings, collector computer hardware, etc.*	Smart Meter			$ 9,765	$ -	$ -	$ 9,765
Total Advanced Metering Regional Collector (AMRC) (includes LAN)		$ -	$ -	$ 312,165	$ -	$ -	$ 312,165

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
1.3.1 Computer Hardware	Comp. Hard.			$ -	$ -	$ 147,000	$ 147,000
1.3.2 Computer Software	Comp. Soft.			$ -	$ -	$ 5,103	$ 5,103
1.3.3 Computer Software Licence & Installation (includes hardware & software *may include AS/400 disc space, backup & recovery computer, UPS, etc*	Comp. Soft.			$ -	$ -	$ 22,680	$ 22,680
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ 174,783	$ 174,783

1.4 WIDE AREA NETWORK (WAN)	Asset Type	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
1.4.1 Activation Fees	Tools & Equip			$ -	$ -	$ -	$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONA	Asset Type	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
1.5.1 Customer equipment (including repair of damaged equipment)	Other Equip.			$ -	$ -	$ -	$ -
1.5.2 AMI Interface to CIS	Comp. Soft.			$ -	$ 2,100	$ 144,249	$ 146,349
1.5.3 Professional Fees	Comp. Soft.		$ 75,028	$ 44,461	$ 49,976	$ 65,100	$ 234,565
1.5.4 Integration	Comp. Soft.			$ -	$ -	$ 114,765	$ 114,765
1.5.5 Program Management	Comp. Soft.			$ 150,816	$ 115,861	$ 78,742	$ 345,419
1.5.6 Other AMI Capital	Comp. Soft.			$ -	$ -	$ -	$ -
Total Other AMI Capital Costs Related To Minimum Functionality		$ -	$ 75,028	$ 195,277	$ 167,937	$ 402,856	$ 841,098

		2006	2007	2008	2009	2010	Total
Total Capital Costs		$ -	$ 75,028	$ 531,472	$ 688,374	$ 6,687,952	$ 7,982,826

O M & A

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
2.1.1 Maintenance *may include meter reverification costs, etc.*			$ -	$ 80,955	$ 38,955	$ 119,910
Total Incremental AMI Operation Expenses	$ -	$ -	$ -	**$ 80,955**	**$ 38,955**	**$ 119,910**

2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
2.2.1 Maintenance			$ -	$ -		$ -
Total Advanced Metering Regional Collector (AMRC) (includes LAN)	$ -	$ -	$ -	$ -	$ -	$ -

2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
2.3.1 Hardware Maintenance *may include server support, etc*			$ -	$ 57,750		$ 57,750
2.3.2 Software Maintenance *may include maintenance support, etc.*			$ -	$ -	$ 125,757	$ 125,757
Total Advanced Metering Control Computer (AMCC)	$ -	$ -	$ -	**$ 57,750**	**$ 125,757**	**$ 183,507**

2.4 WIDE AREA NETWORK (WAN)

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
2.4.1 WIDE AREA NETWORK (WAN) *may include serial to Ethernet hardware, etc.*			$ -	$ -		$ -
Total Incremental Other Operation Expenses	$ -	$ -	$ -	$ -	$ -	$ -

2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
2.5.1 Business Process Redesign			$ -	$ -	$ 85,680	$ 85,680
2.5.2 Customer Communication *may include project communication. etc.*			$ -	$ -	$ -	$ -
2.5.3 Program Management			$ -	$ -	$ -	$ -
2.5.4 Change Management *may include training, etc.*			$ -	$ -	$ 42,420	$ 42,420
2.5.5 Administration Cost			$ -	$ -	$ -	$ -
2.5.6 Other AMI Expenses			$ -	$ -	$ -	$ -
Total 2.5 Other AMI OM&A Costs Related To Minimum Functionality	$ -	$ -	$ -	$ -	**$ 128,100**	**$ 128,100**

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted	Total
Total O M & A Costs	$ -	$ -	$ -	**$ 138,705**	**$ 292,812**	**$ 431,517**

Sheet 2. LDC Assumptions and Data

Assumptions:
1. Year assumed January to December
2. Amortization is straight line and has half year rule applied in first year

	2006 EDR Data Information	2007	2008	2009	2010
Capital Structure					
Deemed Short Term Debt %			0%	0%	4%
Deemed Debt (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 18)	50%	50%	53%	57%	56%
Deemed Equity (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 19)	50%	50%	47%	43%	40%
Deemed Short Term Debt Rate%			0.00%	0.00%	1.33%
Weighted Debt Rate (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 25)	7.25%	7.25%	7.25%	7.25%	7.62%
Proposed ROE (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell E 32)	9.00%	9.00%	9.00%	9.00%	8.01%
Weighted Average Cost of Capital	8.13%	8.13%	8.07%	8.01%	7.52%
Working Capital Allowance %	15.00%	15.00%	15.00%	15.00%	15.00%
2006 EDR Tax Rate					
Corporate Income Tax Rate *(from 2006 PILs Sheet "Test Year PILs,Tax Provision" Cell D 14)*	36.12%	36.12%	33.50%	33.00%	31.00%

Capital Data:

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	Total
Smart Meter	$ -	$ -	$ 312,165	$ 503,637	$ 6,088,263	$6,904,065
Computer Hardware	$ -	$ -	$ -	$ 16,800	$ 169,050	$ 185,850
Computer Software	$ -	$ 75,028	$ 219,307	$ 167,937	$ 430,639	$ 892,911
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Costs	$ -	$ 75,028	$ 531,472	$ 688,374	$ 6,687,952	$7,982,826
	-	-	-	-	-	-

Operating Expense Data:

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	Total
2.1 Advanced Metering Communication Device (AMCD)	$ -	$ -	$ -	$ 80,955	$ 38,955	$ 119,910
2.2 Advanced Metering Regional Collector (AMRC) (includes LAN)	$ -	$ -	$ -	$ -	$ -	$ -
2.3 Advanced Metering Control Computer (AMCC)	$ -	$ -	$ -	$ 57,750	$ 125,757	$ 183,507
2.4 Wide Area Network (WAN)	$ -	$ -	$ -	$ -	$ -	$ -
2.5 Other AMI OM&A Costs Related To Minimum Functionality	$ -	$ -	$ -	$ -	$ 128,100	$ 128,100
Total O M & A Costs	$ -	$ -	$ -	$ 138,705	$ 292,812	$ 431,517
	-	-	-	-	-	-

Per Meter Cost Split:

	Per Meter	Installed	Investment	% of Invest
Smart meter including installation	$ 176.90	39,028	$ 6,904,065	82%
Computer Hardware Costs	$ 4.76	39,028	$ 185,850	2%
Computer Software Costs	$ 22.88	39,028	$ 892,911	11%
Tools & Equipment	$ -	39,028	$ -	0%
Other Equipment	$ -	39,028	$ -	0%
Smart meter incremental operating expenses	$ 11.06	39,028	$ 431,517	5%
Total Smart Meter Capital Costs per meter	$ 215.60		$ 8,414,343	100%

Depreciation Rates

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted
Smart Meter (years)	15	15	15	15	15
Computer Hardware (years)	10	10	10	10	10
Computer Software (years)	5	5	5	5	5
Tools & Equipment (years)	10	10	10	10	10
Other Equipment (years)	10	10	10	10	10

CCA Rates

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted
CCA Class	47	47	47	47	47
Smart Meter	8%	8%	8%	8%	8%
CCA Class	45	45	50	50	50
Computer Equipment	45%	45%	55%	55%	55%
CCA Class	8	8	8	8	8
General Equipment	20%	20%	20%	20%	20%

Sheet 3. Smart Meter Revenue Requirement Calculation

	2007 Audited Actual			2008 Audited Actual			2009 Forecasted			2010 Forecasted		
Average Asset Values												
Net Fixed Assets Smart Meters	$ -			$ 150,879.75			$ 534,778.55			$3,683,264.60		
Net Fixed Assets Computer Hardware	$ -			$ -			$ 7,980.00			$ 95,418.75		
Net Fixed Assets Computer Software	$ 33,762.60			$ 158,710.55			$ 296,034.05			$ 489,732.55		
Net Fixed Assets Tools & Equipment	$ -			$ -			$ -			$ -		
Net Fixed Assets Other Equipment	$ -			$ -			$ -			$ -		
Total Net Fixed Assets	$ 33,762.60	$ 33,762.60		$ 309,590.30	$ 309,590.30		$ 838,792.60	$ 838,792.60		$4,268,415.90	$4,268,415.90	
Working Capital												
Operation Expense	$ -			$ -			$ 138,705.00			$ 292,812.00		
Working Capital %	$ -	$ -		$ -	$ -		$ 20,805.75	$ 20,805.75		$ 43,921.80	$ 43,921.80	
Smart Meters included in Rate Base		$ 33,762.60			$ 309,590.30			$ 859,598.35			$4,312,337.70	
Return on Rate Base												
Deemed Short Term Debt %				0.0%			0.0%			4.0%	$ 172,493.51	
Deemed Long Term Debt %	50.0%	$ 16,881.30		53.3%	$ 165,011.63		56.7%	$ 487,392.26		56.0%	$2,414,909.11	
Deemed Equity %	50.0%	$ 16,881.30		46.7%	$ 144,578.67		43.3%	$ 372,206.09		40.0%	$1,724,935.08	
		$ 33,762.60			$ 309,590.30			$ 859,598.35			$4,312,337.70	
Deemed Short Term Debt Rate%				0.0%			0.0%			1.3%	$ 2,294.16	
Weighted Debt Rate *(3. LDC Assumptions and Data)*	7.3%	$ 1,223.89		7.3%	$ 11,963.34		7.3%	$ 35,335.94		7.6%	$ 184,016.07	
Proposed ROE *(3. LDC Assumptions and Data)*	9.0%	$ 1,519.32		9.0%	$ 13,012.08		9.0%	$ 33,498.55		8.0%	$ 138,167.30	
Return on Rate Base		$ 2,743.21	$ 2,743.21		$ 24,975.42	$ 24,975.42		$ 68,834.49	$ 68,834.49		$ 324,477.54	$ 324,477.54
Operating Expenses												
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			$ -			$ -			$ 138,705.00			$ 292,812.00
Amortization Expenses												
Amortization Expenses - Smart Meters		$ -			$ 10,405.50			$ 37,598.90			$ 257,328.90	
Amortization Expenses - Computer Hardware		$ -			$ -			$ 840.00			$ 10,132.50	
Amortization Expenses - Computer Software		$ 7,502.80			$ 36,936.30			$ 75,660.70			$ 135,518.30	
Amortization Expenses - Tools & Equipment		$ -			$ -			$ -			$ -	
Amortization Expenses - Other Equipment		$ -			$ -			$ -			$ -	
Total Amortization Expenses			$ 7,502.80			$ 47,341.80			$ 114,099.60			$ 402,979.70
Revenue Requirement Before PILs			$ 10,246.01			$ 72,317.22			$ 321,639.09			$ 1,020,269.23
Calculation of Taxable Income												
Incremental Operating Expenses			$ -			$ -			-$ 138,705.00			-$ 292,812.00
Depreciation Expenses			-$ 7,502.80			-$ 47,341.80			-$ 114,099.60			-$ 402,979.70
Interest Expense			-$ 1,223.89			-$ 11,963.34			-$ 35,335.94			-$ 186,310.24
Taxable Income For PILs			$ 1,519.32			$ 13,012.08			$ 33,498.55			$ 138,167.30
Grossed up PILs *(5. PILs)*			-$ 4,291.93			-$ 21,137.19			-$ 21,681.89			-$ 15,793.87
Revenue Requirement Before PILs			$ 10,246.01			$ 72,317.22			$ 321,639.09			$ 1,020,269.23
Grossed up PILs *(5. PILs)*			-$ 4,291.93			-$ 21,137.19			-$ 21,681.89			-$ 15,793.87
Revenue Requirement for Smart Meters			**$ 5,954.08**			**$ 51,180.03**			**$ 299,957.20**			**$ 1,004,475.37**

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening UCC	$ -	$ -	$ -	$ 299,678.40	$ 759,195.65
Capital Additions	$ -	$ -	$ 312,165.00	$ 503,637.00	$ 6,088,262.89
UCC Before Half Year Rule	$ -	$ -	$ 312,165.00	$ 803,315.40	$ 6,847,458.54
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ 156,082.50	$ 251,818.50	$ 3,044,131.44
Reduced UCC	$ -	$ -	$ 156,082.50	$ 551,496.90	$ 3,803,327.09
CCA Rate Class	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%
CCA	$ -	$ -	$ 12,486.60	$ 44,119.75	$ 304,266.17
Closing UCC	$ -	$ -	$ 299,678.40	$ 759,195.65	$ 6,543,192.37

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening UCC	$ -	$ -	$ 58,146.70	$ 185,163.59	$ 217,257.94
Capital Additions Computer Hardware	$ -	$ -	$ -	$ 16,800.00	$ 169,050.00
Capital Additions Computer Software	$ -	$ 75,028.00	$ 219,307.00	$ 167,937.00	$ 430,639.00
UCC Before Half Year Rule	$ -	$ 75,028.00	$ 277,453.70	$ 369,900.59	$ 816,946.94
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 37,514.00	$ 109,653.50	$ 92,368.50	$ 299,844.50
Reduced UCC	$ -	$ 37,514.00	$ 167,800.20	$ 277,532.09	$ 517,102.44
CCA Rate Class	45	45	50	50	50
CCA Rate	45%	45%	55%	55%	55%
CCA	$ -	$ 16,881.30	$ 92,290.11	$ 152,642.65	$ 284,406.34
Closing UCC	$ -	$ 58,146.70	$ 185,163.59	$ 217,257.94	$ 532,540.60

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening UCC	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -

Sheet 4. PILs Calculation

	2007	2008	2009	2010
INCOME TAX	Audited Actual	Audited Actual	Forecasted	Forecasted
Net Income	$ 1,519.32	$ 13,012.08	$ 33,498.55	$ 138,167.30
Amortization	$ 7,502.80	$ 47,341.80	$ 114,099.60	$ 402,979.70
CCA - Smart Meters	$ -	-$ 12,486.60	-$ 44,119.75	-$ 304,266.17
CCA - Computers	-$ 16,881.30	-$ 92,290.11	-$ 152,642.65	-$ 284,406.34
CCA - Other Equipment	$ -	$ -	$ -	$ -
Change in taxable income	-$ 7,859.18	-$ 44,422.83	-$ 49,164.25	-$ 47,525.51
Tax Rate *(3. LDC Assumptions and Data)*	36.12%	33.50%	33.00%	31.00%
Income Taxes Payable	-$ 2,838.74	-$ 14,881.65	-$ 16,224.20	-$ 14,732.91

ONTARIO CAPITAL TAX				
Smart Meters	$ -	$ 301,759.50	$ 767,797.60	$6,598,731.59
Computer Hardware	$ -	$ -	$ 15,960.00	$ 174,877.50
Computer Software	$ 67,525.20	$ 249,895.90	$ 342,172.20	$ 637,292.90
Tools & Equipment	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -
Rate Base	$ 67,525.20	$ 551,655.40	$1,125,929.80	$7,410,901.99
Less: Exemption	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ 67,525.20	$ 551,655.40	$1,125,929.80	$7,410,901.99
Ontario Capital Tax Rate	0.225%	0.225%	0.225%	0.075%
Net Amount (Taxable Capital x Rate)	$ 151.93	$ 1,241.22	$ 2,533.34	$ 5,558.18

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	-$ 2,838.74	-$ 14,881.65	-$ 16,224.20	-$ 14,732.91
Change in OCT	$ 151.93	$ 1,241.22	$ 2,533.34	$ 5,558.18
PIL's	-$ 2,686.81	-$ 13,640.42	-$ 13,690.86	-$ 9,174.73
	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
Change in Income Taxes Payable	-$ 4,443.86	-$ 22,378.42	-$ 24,215.23	-$ 21,352.04
Change in OCT	$ 151.93	$ 1,241.22	$ 2,533.34	$ 5,558.18
PIL's	**-$ 4,291.93**	**-$ 21,137.19**	**-$ 21,681.89**	**-$ 15,793.87**

Sheet 5. Avg Net Fixed Assets &UCC

Smart Meter Average Net Fixed Assets

Net Fixed Assets - Smart Meters	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening Capital Investment	$ -	$ -	$ -	$ 312,165.00	$ 815,802.00
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ 312,165.00	$ 503,637.00	$ 6,088,262.89
Closing Capital Investment	$ -	$ -	$ 312,165.00	$ 815,802.00	$ 6,904,064.89
Opening Accumulated Amortization	$ -	$ -	$ -	$ 10,405.50	$ 48,004.40
Amortization (15 Years Straight Line)	$ -	$ -	$ 10,405.50	$ 37,598.90	$ 257,328.90
Closing Accumulated Amortization	$ -	$ -	$ 10,405.50	$ 48,004.40	$ 305,333.30
Opening Net Fixed Assets	$ -	$ -	$ -	$ 301,759.50	$ 767,797.60
Closing Net Fixed Assets	$ -	$ -	$ 301,759.50	$ 767,797.60	$ 6,598,731.59
Average Net Fixed Assets	$ -	$ -	$ 150,879.75	$ 534,778.55	$ 3,683,264.60

Net Fixed Assets - Computer Hard	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening Capital Investment	$ -	$ -	$ -	$ -	$ 16,800.00
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ 16,800.00	$ 169,050.00
Closing Capital Investment	$ -	$ -	$ -	$ 16,800.00	$ 185,850.00
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ 840.00
Amortization (10 Years Straight Line)	$ -	$ -	$ -	$ 840.00	$ 10,132.50
Closing Accumulated Amortization	$ -	$ -	$ -	$ 840.00	$ 10,972.50
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ 15,960.00
Closing Net Fixed Assets	$ -	$ -	$ -	$ 15,960.00	$ 174,877.50
Average Net Fixed Assets	$ -	$ -	$ -	$ 7,980.00	$ 95,418.75

Net Fixed Assets - Computer Softv	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening Capital Investment	$ -	$ -	$ 75,028.00	$ 294,335.00	$ 462,272.00
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ 75,028.00	$ 219,307.00	$ 167,937.00	$ 430,639.00
Closing Capital Investment	$ -	$ 75,028.00	$ 294,335.00	$ 462,272.00	$ 892,911.00
Opening Accumulated Amortization	$ -	$ -	$ 7,502.80	$ 44,439.10	$ 120,099.80
Amortization Year 1 (5 Years Straight Line)	$ -	$ 7,502.80	$ 36,936.30	$ 75,660.70	$ 135,518.30
Closing Accumulated Amortization	$ -	$ 7,502.80	$ 44,439.10	$ 120,099.80	$ 255,618.10
Opening Net Fixed Assets	$ -	$ -	$ 67,525.20	$ 249,895.90	$ 342,172.20
Closing Net Fixed Assets	$ -	$ 67,525.20	$ 249,895.90	$ 342,172.20	$ 637,292.90
Average Net Fixed Assets	$ -	$ 33,762.60	$ 158,710.55	$ 296,034.05	$ 489,732.55

Net Fixed Assets - Tools & Equipn	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening Capital Investment	$ -	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipme	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Forecasted	2010 Forecasted
Opening Capital Investment	$ -	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -

EXHIBIT 10
LOST REVENUE ADJUSTMENT (LRAM)

LOST REVENUE ADJUSTMENT (LRAM)

OVERVIEW:

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 (Third Tranche). The Minister's approval was conditional upon a commitment to invest in conservation and demand management (CDM) an equivalent of one year's return. Consequently, Whitby Hydro applied to increase its rates and on February 17, 2005 received approval for its CDM Plan of approximately $1.3M. The initial plan incorporated eleven different programs however, as a result of ongoing review and monitoring of programs by an internal CDM committee, a revised CDM plan was submitted to the Board early in 2007 which received Board approval on March 22, 2007. This revised plan incorporated nineteen programs in total.

During 2007, the provincial Ontario Power Authority (OPA) announced a new offering of CDM programs and electricity distributors were given an opportunity to participate by taking primary responsibility for implementation of the programs to their customers. Prior to developing programs which had formal contracts between the distributors and the OPA, a variety of other general CDM programs were initiated by the OPA in which distributors were able to lend their support by promoting the programs within their community. Whitby Hydro has participated in a range of OPA programs and continues to actively promote CDM to its customers and community at large.

Throughout the third tranche program initiative, Whitby Hydro developed a strong presence in the community with respect to creating a culture of conservation and educating its customers on energy efficient technologies as well as guiding them on consumption changes which could lead to energy savings. Once the third tranche programs were completed in 2007, Whitby Hydro wanted to ensure that those programs which were developed to assist some of the more vulnerable customers in the community (i.e. low income and seniors) were not abandoned. Funding for this type of community based CDM program was not readily available from the OPA or through the Board so in order to continue to offer these services, Whitby Hydro self-funded a subset of CDM programs for low income, seniors and community based CDM activities in 2008. The cost of these programs was paid by the shareholder.

Whitby Hydro's CDM efforts have been successful, but it has experienced distribution revenue losses from 2006 to 2009 as a result of the associated decreases in kilowatt hour (kWh) consumption and kilowatt (kW) demand. This is the first opportunity that Whitby Hydro has had to request approval for the recovery of these foregone revenues.

In applying for LRAM adjustments Whitby Hydro followed the Board's *"Guidelines for Electricity Distributor Conservation and Demand Management"* Board File No. EB-2008-0037 issued on March 28, 2008 (the "CDM Guidelines"). The CDM Guidelines describe the Board's policies and procedures with respect to applications for LRAM and SSM recovery associated with distribution rate funded and OPA funded CDM 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 guidance 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 both these documents, Whitby Hydro submits a request to recover historical revenues lost. While there have been no CDM specific adjustments outside of the existing load forecasting methodology undertaken for the 2010 rebasing application (see Exhibit 3), Whitby Hydro understands that the load forecasting methodology would inherently incorporate some impacts of the CDM programs identified in this LRAM application.

Whitby Hydro is requesting recovery of historical LRAM amounts related to select third tranche, OPA, and Whitby Hydro funded programs which were completed by the end of 2008. The LRAM incorporates the impact of these programs from 2006 – 2009. Any lost revenues related to 2009 programs have not been included in this application, but Whitby Hydro intends to file for recovery of these programs in the future once the results are finalized.

In preparing the LRAM application, Whitby Hydro also undertook a review of its eligible programs for the purpose of assessing a SSM request. As the costs for all CDM related programs must be considered for calculations of the TRC values used for SSM applications, Whitby Hydro determined that an SSM claim would be immaterial and consequently no claim has been included in this application. This is largely due to the difficulty in measuring the effects of educational and research based programs, the exclusion of utility-side programs and OPA programs and the additional requirements/costs that would be incurred to substantiate energy savings for custom programs.

In keeping with the CDM Guidelines, Whitby Hydro's Conservation Officer has prepared an Evaluation Report which focuses on the OPA and Whitby Hydro Funded Programs. The CDM Guidelines do not require an Evaluation Report to accompany an LRAM application for programs funded through distribution rates prior to 2007 and as such, the third tranche programs are not included in the Evaluation Report.

ELIGIBLE PROGRAMS:

Whitby Hydro has prepared its LRAM application in accordance with the CDM Guidelines and most recently published OPA Assumptions and Measures List. LRAM is available for programs funded through the OPA and through distribution rates and it applies to programs that are implemented by the distributor within its licensed service area. Distributors may only recover LRAM for revenue losses that can be attributed to the distributor's involvement in the program.

The CDM Guidelines do not specifically reference distributor funded programs, however they do acknowledge the eligibility of programs that are undertaken in partnership with other entities. Paramount to the determination of eligibility is the distributor's involvement in the program. Whitby Hydro programs are described more fully in the Evaluation Report and while there is some partnering with community agencies, the costs associated with the energy efficient technologies included in this LRAM have been fully funded by Whitby Hydro. Given its key role in these programs, Whitby Hydro proposes that these programs meet the eligibility requirements identified in the CDM Guidelines for inclusion in LRAM claims.

It should be noted that Whitby Hydro took a relatively conservative approach with its LRAM calculations to ensure that only measurable and readily verifiable savings have been included in the LRAM request. As a result, Whitby Hydro has included only those third tranche programs for which savings information is provided in the list of recognized inputs and assumptions and has therefore excluded custom type programs from its calculations. In addition, Whitby Hydro has ensured that sufficient time has passed once a program is completed before it has included the savings in the LRAM calculations. In general, for all third tranche and all Whitby Hydro funded programs, the savings identified within a given year are not recognized until the following year (i.e. no prorated savings are included in the year when the energy efficient technology is actually implemented).

THIRD PARTY REVIEW

Whitby Hydro engaged the services of Burman Energy Consultants Group Inc. (BECGI), to perform the following activities:

- Review and finalize LRAM calculations and measurement assumptions to ensure consistency with the CDM Guidelines for eligible programs.
- Provide a report including the relevant details, calculations and assumptions for inclusion in the LRAM application.

- Verify participation levels and act as a third party reviewer in a manner consistent with the CDM Guidelines

BECGI was formerly known as EnerSpectrum Group. The company underwent a name change effective November 1, 2009 but continues to maintain the core staff, skills, knowledge and expertise that it had under the EnerSpectrum Group name. The company continues to serve a primary market of local distribution utilities with services in CDM program evaluation, distribution system analysis, regulatory support, utility management and operations. BECGI has managed both the complete year-end CDM reporting process for distributors on a turnkey basis, and provided specialized support in the preparation of requisite reporting schedules and supporting TRC analysis. The firm holds its Certification of Authorization from the Professional Engineers of Ontario, and is a commercial steering committee member of the Electricity Distributors Association.

BECGI (under both EnerSpectrum Group and BECGI names) has significant experience in the evaluation of CDM program performance and regulatory reporting, and has been involved the following related areas:

- Prepared LRAM and SSM business cases or third party evaluations for 10 distributors since 2007.
- Developed the TRC Calculator tool that automates TRC calculations based on OEB assumptions and tables. This tool, and/or TRC support services are used by more than 25 distributors. The TRC Calculator was upgraded in 2008 and 2009 to automate calculations for LRAM and SSM based on TRC values.
- Evaluated more than 750 individual projects serving some 23 utilities. Currently one of the largest third party evaluators of Electricity Retrofit Incentive Program (ERIP) project evaluation,
- Involved in implementing the Power Savings Blitz (PSB) program for 16 distributors in 39 communities, including project evaluation and audits.

BECGI evaluated Whitby Hydro’s third tranche and Whitby Hydro funded programs and updated the savings calculations to align with the most recently published list of assumptions and measures in accordance with the OEB’s direction letter issued on January 27, 2009 (Board File No. EB-2008-0352). BECGI’s report (LRAM Support) details the assumptions used for each program; identifies the kWh and kW savings (both gross and net of free ridership) by program by customer class; and incorporates the information provided in the OPA 2006-2008 Conservation Report for Whitby Hydro. A copy of BECGI’s report (LRAM Support) is attached as Appendix 10-1

CALCULATION OF PROPOSED LRAM

The LRAM is determined by calculating the energy savings for each customer class and assigning a value to those energy savings using the distributor's Board-approved variable distribution charge appropriate to each class. The calculation does not include any Regulatory Asset Recovery through rate riders. Details of the LRAM calculation have been included in the LRAM Support document.
Whitby Hydro has prepared the LRAM rate rider using the lost revenue calculated in the LRAM Support report plus an applicable amount for carrying costs (interest). Interest charges are required on the lost revenue in order to maintain the value of the unrecovered funds between the time of loss and the time of payment and to cover any associated financing costs. Whitby Hydro has applied the carrying costs to the customer classes in the same proportion as the total lost revenue amounts.

The total LRAM claim is $405,135 (made up of lost revenue of $387,996 plus carrying costs of $17,139). A breakdown of the LRAM claim is as follows:

	Lost Revenue	Proration of Carrying Cost (Interest)	Total LRAM
Residential	355,526	15,397	370,924
GS<50 kW	4,470	165	4,635
GS>50 kW	28,000	1,576	29,576
	387,996	17,139	405,135

The calculated carrying charges (see Table 10-1) assume that lost revenue is accumulated evenly throughout the year and the OEB prescribed rates have been applied to the opening balances each month. Estimates for future interest rates reflect the last published rate at the time of this filing.

1 **Table 10-1: LRAM – Carrying Cost Rates and Calculations**

Year	Month	Monthly Lost Revenue	Closing Balance	Interest Rate*	Interest $
2006	Jan	4,093	4,093	7.25%	
	Feb	4,093	8,187	7.25%	25
	Mar	4,093	12,280	7.25%	49
	Apr	4,093	16,374	7.25%	74
	May	4,093	20,467	4.14%	56
	Jun	4,093	24,560	4.14%	71
	Jul	4,093	28,654	4.59%	94
	Aug	4,093	32,747	4.59%	110
	Sep	4,093	36,840	4.59%	125
	Oct	4,093	40,934	4.59%	141
	Nov	4,093	45,027	4.59%	157
	Dec	4,093	49,121	4.59%	172
2007	Jan	7,335	56,456	4.59%	188
	Feb	7,335	63,791	4.59%	216
	Mar	7,335	71,127	4.59%	244
	Apr	7,335	78,462	4.59%	272
	May	7,335	85,798	4.59%	300
	Jun	7,335	93,133	4.59%	328
	Jul	7,335	100,469	4.59%	356
	Aug	7,335	107,804	4.59%	384
	Sep	7,335	115,139	4.59%	412
	Oct	7,335	122,475	5.14%	493
	Nov	7,335	129,810	5.14%	525
	Dec	7,335	137,146	5.14%	556
2008	Jan	11,039	148,184	5.14%	587
	Feb	11,039	159,223	5.14%	635
	Mar	11,039	170,261	5.14%	682
	Apr	11,039	181,300	4.08%	579
	May	11,039	192,339	4.08%	616
	Jun	11,039	203,377	4.08%	654
	Jul	11,039	214,416	3.35%	568
	Aug	11,039	225,454	3.35%	599
	Sep	11,039	236,493	3.35%	629
	Oct	11,039	247,532	3.35%	660
	Nov	11,039	258,570	3.35%	691
	Dec	11,039	269,609	3.35%	722
2009	Jan	9,866	279,474	2.45%	550
	Feb	9,866	289,340	2.45%	571
	Mar	9,866	299,206	2.45%	591
	Apr	9,866	309,071	1.00%	249
	May	9,866	318,937	1.00%	258
	Jun	9,866	328,802	1.00%	266
	Jul	9,866	338,668	0.55%	151
	Aug	9,866	348,534	0.55%	155
	Sep	9,866	358,399	0.55%	160
	Oct	9,866	368,265	0.55%	164
	Nov	9,866	378,130	0.55%	169
	Dec	9,866	387,996	0.55%	173
2010	Jan		387,996	0.55%	178
	Feb		387,996	0.55%	178
	Mar		387,996	0.55%	178
	Apr		387,996	0.55%	178
Total Interest					17,139

* OEB Prescribed Interest Rates

PROPOSED RATE RIDERS AND BILL IMPACTS

Whitby Hydro proposes a recovery of lost revenue totaling $405,135 through a volumetric rate rider over a two year period. A four year recovery period (consistent with the period proposed for the recovery of regulatory assets) was the original preference however, using this period of time would drive the rate rider to a level that was negligible. As a result, a two year recovery period is proposed. The calculation of the rate rider is detailed in Table 10-2.

Table 10-2: Proposed LRAM Rate Rider

Customer Class Name	LRAM Amount	Annual Recovery	Annual Volume	Rate Rider	per
Residential	370,924	185,462	350,407,180	$0.0005	kWh
General Service Less Than 50 kW	4,635	2,318	75,150,446	$0.0000	kWh
General Service 50 to 4,999 kW	29,576	14,788	966,330	$0.0153	kW
Unmetered Scattered Load			2,493,809		kWh
Sentinel Lighting			120		kW
Street Lighting			24,361		kW
TOTAL	**405,135**	**202,568**			

Bill Impacts have been identified in Table 10-3 for the Residential and GS>50kW customer classes. Both classes had total bill impacts well below 10% based on 2010 proposed rates.

Table 10-3: Bill Impacts

	Residential	GS>50 kW
kWh	800	40,000
kW	n/a	100
LRAM rate rider	0.0005 /kWh	0.0153 /kW
LRAM $	0.40	1.53
Total Bill	99.05	4,027.12
LRAM as a % of Total Bill	0.40%	0.04%

EVALUATION REPORT

Refer to Appendix 10-1

CONSERVATION AND DEMAND SIDE MANAGEMENT - EVALUATION REPORT

INTRODUCTION

Whitby Hydro Electric Corporation (Whitby Hydro) is one of the oldest public utilities in Ontario, serving approximately 40,000 customers within the Town of Whitby and the communities of Brooklin, Myrtle and Ashburn. With over 106 years of providing progressive and innovative distribution services, Whitby Hydro continues to lead the utility industry in engineering design, customer service and conservation.

Whitby Hydro began its CDM initiative in 2005 upon receiving approval by the OEB for its third tranche CDM plan. The initial plan incorporated eleven different programs. The plan was revised in March 2007 to allow for a concentrated effort on the implementation and development of effective conservation programs. The plan revision was structured to incorporate established successful third tranche programs while ensuring there was no overlap with pending OPA program agreements between Whitby Hydro and the OPA.

In addition to the OPA and third tranche programs, Whitby Hydro introduced community based programs that promoted conservation throughout the community and allowed an opportunity for higher need customer segments to benefit from implementing conservation measures.

Whitby Hydro's goal is to become a leader in community based conservation programs that focus on education and results oriented programs. In 2006 a corporate Conservation Officer position was created to coordinate the OPA initiatives and develop community programs to increase awareness of conservation efforts within and outside of the utility.

The following summary outlines the evaluation of the initiatives carried out by Whitby Hydro particularly with respect to Whitby Hydro funded and OPA funded CDM programs. Third tranche evaluations have already been completed as part of the OEB annual reporting requirements.

WHITBY HYDRO FUNDED PROGRAMS 2008

Whitby Hydro funded programs have been designed to address the needs of those customers who would receive the greatest benefit financially from conserving energy as well as target families with school age children to start the process of developing a generation of conservationists. The programs concentrate on three core customer segments: low income, seniors and school age families. These programs are primarily information based, but also provide give away opportunities to demonstrate use of the technology.

Whitby Hydro tracks program results by keeping detailed records of any equipment distributed and requires participants such as seniors to sign when receiving any conservation products. These records help us monitor and track the success of the program and create a mailing list for future programs and/or follow up.

The programs have been very successful and it is Whitby Hydro's intent to continue with the programs into the future. All kWh savings identified in this report are net of free ridership.

<u>Whitby Hydro Low Income Program</u>:

2008 Program: 108,864 kWh/year saved
Budget - $16.2K

The Whitby Hydro Low Income Program started in 2007 and targets low income families through the Whitby Food Bank. The program was adopted because it targets a customer base which financially is challenged to implement conservation initiatives but would receive the greatest benefit from the cost savings. The program is split into three categories as follows:

Energy Green boxes – This initiative is a partnership between Whitby Hydro, Enbridge Distribution Company and Friends of the Earth (charitable, not-for-profit grassroots environmental advocates) to provide low income families with Energy Green boxes which includes home winterization tools and two CFL light bulbs. The program began as part of the third tranche initiative in 2007 and has issued 1400 boxes per year for needy families.

Bags for Life Program - In partnership with Sobey's, Whitby Hydro provides the food bank with reusable cloth bags. The Bags for Life program complements the Energy Green boxes by encouraging a balanced approach to conservation which looks at not only energy conservation but the total environmental impact of recycling. In 2008 one thousand bags were distributed.

Lessons Learned

- Programs for low income customers must be simple, easy to implement and easy to understand.
- Low income programs are successful when aligned with other agencies who have already "pre-qualified" the customers – ex. The Salvation Army Food Bank where social workers are on site, have pre-qualified the customers and know the families by name.

- Low income programs require the assistance of social workers (who have established relationships and are viewed as trusted advisors to low income families) to raise awareness of the programs and help educate the customers on the benefits of conserving electricity.
- Other tools to improve energy/cost savings should be considered and are currently planned for 2009. Devices such as lamp timers would benefit these customers to control lighting and other appliances for efficiency and security purposes. These types of equipment are beneficial especially as we move closer to the introduction of time of use pricing.

Whitby Hydro Seniors Program:

2008 Program: 69,984kWh/year saved
Budget $19.5K

The Whitby Hydro Seniors Program started in 2006 as part of the third tranche initiative and targets Senior Citizens through the Whitby Seniors Activity Centre. The program was adopted because it targets a more vulnerable group, who rely on fixed incomes and are very sensitive to price increases.

The demographic typically is less mobile and more challenged in accessing conservation products and programs which makes it even more important to bring the program to them.
The program involves education sessions on conservation for seniors as well as a light bulb exchange program that allows seniors to exchange incandescent bulbs for CFL bulbs (3 for 3) and Whitby Hydro distributed 1,800 light bulbs in 2008.

Lessons Learned

- Seniors need conservation programs which are “simple and easy” to implement.
- Seniors are a vulnerable group, who rely on fixed incomes and are very sensitive to price increases. As a result, they are also very interested in getting involved and taking part in conservation (which helps them save money).
- Seniors programs must be designed to “go the extra mile” and make sure that all barriers are removed and addressed in the program design stage (example, a simple lighting exchange program should be augmented to allow for additional assistance if required to help install these measures in the home where a senior may not be able to take care of this themselves).
- Seniors programs must be designed to help educate the customer as well – this is an important issue because many seniors do not understand new technology and may be reluctant to change (added effort required to promote social marketing techniques and influence behaviour change).

- Seniors programs are most effective when there is an opportunity to market the program at a social networking event – because “word of mouth” from trusted sources is an effective means of communication amongst seniors.
- Future programs will consider the introduction of additional easy to understand concepts and tools such as lamp timers (planned for 2009).

<u>Whitby Hydro Community Events:</u>

2008 Program: 162,907/year saved
Budget: $18.9K

To help promote conservation throughout the Town of Whitby, Whitby Hydro implemented a Community Events program which involved participation at between 25 and 32 community planned events throughout the town each year. Events included the Spring Home & Garden Show, Earth Day, Music in the Park, Safety Day, Town Carnival, Movie Nights, Harvest Festival, Heritage Day, World Planning Day etc. Whitby Hydro distributed compact fluorescent light (CFL) bulbs and brochures offering energy saving tips for consumers and provided the community the opportunity to discuss conservation with staff.

Whitby Hydro distributed 4,190 light bulbs in 2008.

Lessons Learned

- Well-received method of marketing and cross-promotion of various conservation programs.
- Community events provide a relaxed atmosphere and opportunity to dialogue with customers about the details of the program (events take place on weekends when customers are not as rushed and take the time to dialogue and explore).
- LDC participation at local community events help build trusting relationship with customers – which is the foundation required for on-going support of present and future conservation programs.

OPA PROGRAMS

<u>Great Refrigerator Roundup:</u>

2007 Program: 190,206kWh/year saved
Budget: $30K
2008 Program: 354,010kWh/year saved
Budget: $44.5K

Introduction

In 2007 the OPA launched various LDC Conservation and Demand Management Programs. One of the programs was the Great Refrigerator Roundup (GRRP) which provided customers an opportunity to dispose of old inefficient refrigerators and freezers in an environmentally friendly manner at no cost to the customer.

Upon entering into a Master Agreement with the OPA, Whitby Hydro was able to participate in the Great Refrigerator Roundup initiative.

Program Description

The GRR program was centrally administered by the OPA and promoted locally by Whitby Hydro. Whitby Hydro began educating customers on the Great Refrigerator Roundup in the spring of 2007. Posters were installed around the office and bill inserts were distributed to over 35,000 residential customers. Staff was trained on the benefits and savings of disposing of older inefficient appliances and to direct enquiries to the proper OPA department (centralized call-centre).

To enhance the promotion of the program, Whitby Hydro educated customers at public events and fairs. Since the introduction of the program 1,514 refrigerators have been removed from the Whitby Hydro grid.

In 2007, 697 appliances where retired and in 2008 an additional 817 appliances were retired.

Results Verification

Measurement and verification for this program is handled by the OPA. The OPA provides the utility with a report confirming the number of appliances retired. The numbers in this report were provided by the OPA. The kWh saved are based on the OPA 2006-2008 Conservation Results Report (November 10, 2009).

Lessons Learned

- Initial program launch issues included call centre delays and scheduling delays (centralized call centre underestimated the influx of calls). When delays became apparent, Whitby Hydro had to ensure staff was prepared to handle and address any related customer calls, comments and frustrations. It was necessary to keep marketing and promotional efforts as flexible as possible until delays were addressed by the OPA.

- The most effective marketing message for this type of program is the dollar value savings for customers – since many customers were unaware of just how much it was costing them to run an old inefficient secondary beer fridge ($120 -150 per year).
- The environmental impacts of recycling every part of the appliance and avoiding waste going to landfill ("from fridges to bridges") was another value-added benefit for the customer, but did not appear to be the key driver for their decision making .
- Involving local retailers to help promote the program was very effective, since they were involved in face-to-face discussions with target customers who were getting rid of old appliances and replacing them with new (very timely and targeted approach).
- The GRRP is a successful program because it is well thought out in the program design stage and many customer barriers were addressed – ex. removal from basement of home by GRRP representatives helped in cases were customers had little or no means of getting the appliance to the curb.
- Bill inserts proved a very effective means of marketing, especially when the message was re-enforced through mass market campaigns (which included radio, TV, newspapers, etc).

<u>Electricity Retrofit Incentive Program:</u>

2007 Program: 461,125 kWh/year saved
90.5 kW/year saved
Budget: $70K
Targets: 3 prescriptive/1 custom
Actuals: 3 prescriptive/1 custom/1 combined application

Introduction

The Electricity Retrofit Incentive Program was initiated in 2007 and targets all commercial, industrial, institutional and agricultural customers (approximately, 2,457 customers throughout Whitby). The program provides incentives to commercial customers for predefined technologies such as lighting, motors, heating, ventilation, air conditioning and overall electricity systems.

Customers were required to register for the program in 2007 but had 12 months to implement the measures. The kWh reflected in this report represent projects applied for in 2007 and completed up to the end of 2008.

Program Description

The Electricity Retrofit Incentive Program (ERIP) is a standard offer designed to encourage small, medium and large commercial, industrial, institutional and agricultural businesses to install energy efficient products when they retrofit their buildings. Qualifying energy efficiency and demand management measures may be chosen from a pre-defined (prescriptive) list or submitted as a custom project.

Brochures about the program were direct mailed to all commercial customers. This represented approximately 2,457 customers. In addition to the mail out, representatives of Whitby Hydro visited customers to promote and discuss the program.

To participate in the program, the customer is required to fill out an application for either a prescriptive or custom project and submit it to the utility. Once the project is approved, the customer must implement the improvements over a specified period of time, have the completion of the project verified by the Utility, and then they will receive the incentive payment.

Whitby Hydro did not participate in this program during 2008 due to concerns associated with the revised structure of the program contract which left additional cost risk with the distributors. Whitby Hydro has re-engaged in 2009 as the concerns with the contract risks have been addressed.

Results Verification

Measurement verification for this program is through a third party, Marbek Resources, a firm of certified Measurement and Verifications (M&V) specialists. Marbek reviews each application received for both prescriptive and custom measures including engineering estimates of proposed projects. In addition, Marbek verified that projects were completed and actually delivering expected savings. These results were further verified by the OPA.

Lessons Learned

- This program has been well-received by Commercial customers with the Prescriptive List of Measures offering the simple and easiest approach.
- Program applications, guidelines and worksheets help to answer any questions customers may have about the program (program design effective).
- Most applications received were for lighting retrofits – this is likely because it is a simple measure and the higher incentives for lighting helped to push these types of projects.

- To continue momentum and generate more program interest, higher incentives are required for other measures, such as HVAC, motors and more (where projects are cost-effective but paybacks are still too high and may not meet typical hurdle rates for commercial customers).
- Confusion in the marketplace arose when other programs were introduced which appeared to be similar – i.e. BOMA Program, CME Program, Better Buildings Partnership Program, MEER Program, BIP Program and more (while similar in nature, these programs offer differing incentive levels and customers are confused as to which program applies or which program is best). Whitby Hydro worked with customers to identify which program/s was most suitable for their needs and could provide greatest value for the project.

EDA Community Initiatives:

2008 Program: 116,640kWh/year saved
Budget: $27K

Introduction

The LDC Community Initiatives Fund was introduced in July 2008. It is a result of a joint collaboration between the Ontario Power Authority (OPA) and the Electricity Distributors Associations (EDA). The program was designed to provide LDCs with funding for community initiatives to promote electricity conservation awareness. The initiatives which are eligible for the funding could include local activities such as lighting exchange programs, fall fair participation, mall promotions, children's activities in fun fairs, etc. The funding is also meant to assist LDCs who have signed Master Agreements with the OPA, to enhance or promote their standard OPA programs.

The funding is provided to each local distribution company on an annual basis and is in addition to the funding already allocated by the OPA for Standard LDC Programs and Custom Programs covered under the Master CDM Agreement.

Program Description

The LDC Community Initiatives fund was used in 2008 to support two community-based programs in Whitby – i.e. The Summer Students Program and the Town of Whitby (TOW) Community Events Program. The following offers a brief description of each program:

2008 Summer Students Program

This program involved hiring 2 summer university students. The students were trained on:

- Electricity usage in the home,

- Energy issues in Ontario,
- Government's objective to build a culture of conservation,
- OPA conservation programs, and
- Household hints on saving money and saving energy.

The students were outfitted with branded clothing and ID cards and went door-to-door in the Whitby service area promoting current OPA programs. This team provided each customer with a Whitby Hydro Conservation Bag - which was packaged in a bio-degradable bag. In the 2008 bag, the customer received a CFL bulb, a Great Refrigerator Roundup fridge magnet, marketing material for OPA programs as well as a brochure offering helpful hints on "How to Use, How to Choose & How to Dispose of CFL's". The CFL was meant to be a simple and easy way customers could "get started" to conserve and the literature created an awareness of other OPA programs offered that residents could benefit from.

The students successfully visited several thousand Whitby residents during the 2008 summer period. They handed out 3,000 CFL's, helped raise awareness of OPA programs and helped build a culture of conservation in our community.

2008 TOW Community Events program

This conservation program involved the active participation of Whitby Hydro staff at local community events. At these events, WH had a booth set up and we were actively involved promoting the OPA conservation programs. To help build awareness of OPA conservation programs, students distributed OPA marketing material, handed out free CFL's and provided other fun gifts and gadgets for children, such as pens, pencils, etc. These creative marketing measures helped attract attention to our conservation booth. This process worked well because, as the children brought their parents over to our "exciting" booth, we took the opportunity to speak to the parents and promote the OPA programs which were currently underway.

The following is a list of some of the over 25 community events which students and staff participated in during 2008:

Feb 10 2008 - Let's Do Lunch " Live your Dream Event"
Apr 19 2008 - Earth Day 2008 Event
Apr 26 2008 - Pitch-In Brooklin Event
May 10 2008 - Whitby's Great Little Duck Race
Jun 2 2008 - Region of Durham Clean Air Day
Jun 8 2008 - Brooklin Spring Fair
Jun 11 2008 - Music in the Park , Rotary Park

Jun 12 2008 - Music in the Park , Grass Park
Jun 14 2008 - Safety Day Event - Whitby Fire Dept.
Jun 28 2008 - Whitby County Town Carnival
Jul 9 2008 - Music in the Park - Rotary Park
Jul 10 2008 - Music in the Park - Grass Park, Brooklin
Jul 15 2008 - Celebration Sq Performance Series - Whitby Library
Jul 26 2008 - Harbour Days Port Whitby Carnival
Aug 14 2008 - Music in the Park - Rotary Park
Aug 19 2008 - Celebration Square Performance Series at Whitby Library
Sept 13 2008 - Harvest Festival
Sept 20 2008 - Heritage Day
Sept 23 2008 - Durham Region Decorating Workshop
October 17 2008 - Let's Do Lunch "Goes Green" Event

Customers took advantage of the one-on-one discussions and they raised questions about conservation. This program helped to remove barriers which may have prevented customers from getting involved in the past. Any questions or concerns were addressed on the spot and customer feedback told us that this process provided them with immediate answers. Our representatives were also able to put their minds to rest about any possible concerns (e.g., proper disposal of mercury in CFL's) and provide details on program eligibility criteria (e.g., questions about whether or not their spare fridge qualified for the GRRP and more).

Results Verification

The program results reflect the number of light bulbs distributed. For each of these programs Whitby Hydro keeps detailed records of inventory and the number of bulbs distributed at each event.

Lessons Learned

- This program was very well received. Customers saw Whitby Hydro actively involved in the community and willing to openly discuss conservation at their doorstep. The areas targeted for door-to-door visits must be coordinated yearly to prevent repeat coverage.
- It is difficult to cover a large portion of the town using direct door-to-door due to the short season and availability of summer staff.
- Involvement at community events not only helped Whitby Hydro to promote OPA programs but also helped build brand awareness (both OPA & Whitby Hydro). The company was seen to be actively involved in the community, raising energy conservation awareness and promoting a culture of conservation. These actions translate as genuine concern for the needs of local residents and concern for building a sustainable community.

<u>2007 Summer Savings Program:</u>

2007 Program: 530,370kWh/year saved

Budget: $55K

Customers Participating: 6,319

Total Incentives/Rebates: $133.6K

Introduction

The Summer Savings Program was part of the OPA's Conservation and Demand Management Program. It was launched in the spring of 2007 and offered consumers a financial incentive to reduce electricity use by 10% during the summer months (compared to the same summer period in 2006).

With the 2007 Summer Savings program, customers who reduced their electricity consumption by 10% from the previous year received a 10% rebate on their electricity bill. There was no registration; customers were automatically enrolled in the program. Calculations supporting the comparison of summer electricity use (pre and post program, etc.) were completed and rebates were applied on customers' bills immediately following the completion of the billing analysis and comparison of year-to-year energy savings.

Program Description

The Summer Savings program was promoted in conjunction with the OPA by Whitby Hydro through bill inserts (35,000) and posters. The program required software enhancements to the billing system to capture and compare weather normalized energy consumption between 2006 and 2007. Customers who achieved greater than 10% reduction in their energy use received a 10% reduction on their energy bill.

The program helped educate customers on Ontario's growing summer electricity requirements. The program focused on air conditioning demand and the benefits of implementing programmable thermostats and reducing usage during peak periods of energy consumption. Customer Service staff were trained on the providing energy efficiency tips to customers to help them achieve the 10% reduction. To further enhance the promotion of the program, Whitby Hydro educated customers at public events and fairs

Results Verification

The results of this program were tracked and monitored through Whitby Hydro's CIS (Harris) system. Information and results where sent to the OPA for tracking purposes.

Lessons Learned

- 10/10 is a simple message but proved to be a complex program to implement. Consumers were confused about consumption patterns, and LDCs needed to be able to explain detailed calculations in response to customer queries. Explanations included information on how the program worked, timelines, past & present consumption comparisons, weatherization factors, etc.
- Credits were applied on customer bills but in some cases, customers did not notice the credit and in other cases, customers were not sure why they were receiving credit, etc.
- The program proved to be cumbersome and complex for local distribution companies to administer due to required changes to Billing Systems, reports, testing, credit adjustments, call centre training and support.

2008 Summer Sweepstakes Program:

2008 Program: 373,889kWh/year saved

Budget: $43K

Participants: Target: 1,751

Actual: 624

Introduction

The Every Kilowatt Counts Summer Sweepstakes was an Ontario-wide program designed to increase consumer awareness of the importance of reducing electricity demand during the summer peak period. This program was loosely based on the previous year's Summer Savings Program but with the following changes:

- redesigned into a province-wide consumer contest
- consumers were required to enroll in the contest to be eligible to win prizes
- customers who reduced their electricity consumption by 10% from the same period last year did NOT receive a credit on their electricity bill
- Customers were eligible to win two tiers of prizes
- renamed the Every Kilowatt Counts Summer Sweepstakes

To participate in this program, customers were required to "sign-up" either on-line or by calling a centralized OPA call centre. Customers were then encouraged to reduce their electricity consumption during the months of July and August 2008 by 10% as compared to their consumption during the same months in 2007, adjusted for weather normalization. Customers who registered for the program were eligible to win prizes for enrolling (Early Bird Contest) and also for achieving their 10% reduction in their electricity consumption (Grand Prize Draw),

Program Description

The Summer Sweepstakes program was promoted in conjunction with the OPA by Whitby Hydro through bill inserts (35,000), on-bill messages, office posters at community events and more. The program required software enhancements to the billing system to capture and compare weather normalized energy consumption between 2007 and 2008. Customers were encouraged to sign-up for the program by calling a centralized OPA call centre or by signing up on-line.

The program helped educate customers on Ontario's growing summer electricity requirements. The program focussed on air conditioning demand and the benefits of implementing programmable thermostats and reducing usage during peak periods of energy consumption.

Customer Service staff were trained on providing energy efficiency tips to customers to help them achieve the 10% reduction. To enhance the promotion of the program Whitby Hydro educated customers at public events and fairs.

Results Verification

The results of this program were tracked and monitored through Whitby Hydro's CIS (Harris) system. Information and results where sent to the OPA for tracking purposes.

Lessons Learned

- Contest-based program did not attract much interest from residential customers.
- Participation was limited due to the fact that customers were required to go through additional steps to register for the contest.
- To be successful this program should be simplified and streamlined to allow for a one-step process (i.e. customers should not feel they are being inconvenienced or that they must go to great efforts to sign up for a simple contest).
- Marketing of this program at community events proved to be of little value – although customers were made aware of the program, they were required to sign up on-line or by calling a centralized call-centre; with a time lapse and multiple steps, most customers did not follow up

Power Savings Blitz 2008:

2008 Program: 22,733kWh/year saved
Budget: $24K (Sept 2008 – March 2009)

Introduction

The Power Savings Blitz is an OPA program that targets small business customers who have an electricity demand of less than 50kW. Whitby Hydro started supporting the program in 2008 to help address the needs of smaller commercial customers.

The program provides turn-key lighting retrofits for small businesses, valued at up to $1,000 and the energy efficiency improvements provide on-going savings for small businesses.

Program Description

Whitby Hydro hired a third-party contractor to assist in the implementation of this program. The program was initially marketed through a direct mailer to small business customers with demands less than 50kW. At first, customers were a bit skeptical of the free offer which appeared as “too good to be true” and as a result, initial success of the program was limited. In response to the customer feedback received during the launch of the program, Whitby Hydro decided to enhance the marketing by introducing a door to door campaign as well as an out-bound calling campaign. Both these marketing techniques proved to perfectly compliment each other and help to significantly boost participation rates. The key to success in this program appeared to be the dialogue required to help put customers’ minds to rest and assure customers that the program was being offered through a trusted source - Whitby Hydro.

Whitby Hydro provided the third-party contractor with a target list of customers who met the criteria for the program. Representatives then met with the potential customers to discuss the program in greater detail and explain the benefits and savings. The result of the face to face contact was very positive with over 500 customers within Whitby participating in the program since its inception.

Results Verification

Results are verified by a third party and entered into the OPA portal. Completed work orders are signed off by the client and the electrical contractor.

There is a 10% quality assurance sampling completed by a third party contractor. In addition Whitby Hydro performs a 10% sampling of the customers to ensure work was completed and customer satisfaction achieved.

Lessons Learned

- Very effective program with over-whelming response and participation from small businesses.
- Well-designed program which removes all barriers for customers and leaves little or no reason for customers to say “no” or refuse.
- $1,000 in free lighting retrofits was sometimes viewed as a “too good to be true” proposition – which created some skepticism from customers – this concern was quickly addressed by having trained and professional representatives who could explain the program and put customer’s minds to rest.

- Turn-key program design made this program a success because many small business owners do not have the resources or the means to implement these types of energy efficiency measures – and with this program, everything from the initial audit to the installation and the ESA inspection was handled for the customer – all barriers were addressed in the program design.
- Door-to-door marketing and out-bound calling proved to be the most effective marketing method for this program.
- Bill inserts were not very effective with this customer class and feedback received explained that small business owners do not take the time to read bill insert literature.
- Concerns about proper disposal of PCB ballasts and the associated costs were highlighted through this program – 25% of old ballasts removed had PCB's and required special attention and established processes in place to manage the removal and proper disposal.
- Barrier to success for this program involves small businesses who do not make decisions "on-site" and instead require corporate head-office approval – a process needs to be developed to help chain stores, franchises, etc. to approach head-office for approval and communicate this to store-level managers.
- Going forward there is a concern that the majority of customers may have already been approached and participation rates will decline as participation rates meet a natural saturation point.

<u>Other OPA Programs:</u>

Whitby Hydro continues to support and promote OPA programs through direct marketing and community events. Even prior to the OPA's summer conservation programs launch in 2007, Whitby Hydro was preparing to set targets and develop and/or support programs that educate and meet the needs of the customers.

The following OPA programs have been identified as having an impact within the Whitby community:

Residential:

- Every Kilowatt Counts (2006 -2008)
- Cool Savings Rebate Program (2006 – 2008)
- Secondary Fridge Retirement Pilot
- Social Housing Pilot (2007)

General Service:

- High Performance New Construction (2008)
- Demand Response (2006 – 2008)

These programs are directly implemented by the OPA. Distributors lend their support to these programs by promoting them within their service area. Whitby Hydro has been actively involved in conservation initiatives since 2005 through third tranche and subsequently OPA and self-funded programs. Whitby Hydro believes in taking advantage of existing marketing opportunities to promote other like-minded initiatives. With this in mind, Whitby Hydro's strong presence in the community has allowed for a variety of opportunities to highlight the OPA's programs in conjunction with other CDM program offerings. Promotion of these programs is coordinated through Whitby Hydro's Conservation Officer. Communication efforts include bill inserts, website, door-to-door information (delivered by summer students), various community events, educational messages, information sessions with local businesses as well as front entrance promotional posters, messages and information.

The largest general program in Whitby is the Every Kilowatt Counts (EKC) program. In the spring of 2006 the Ontario Power Authority introduced the EKC program. The program provided customers with energy saving product discount coupons. The program was promoted through co-sponsorships by Local Distribution Companies to ensure provincial coverage.

The program consists of two promotional periods per year, one in the spring and one in the fall. Whitby Hydro registered with the Conservation Bureau to be a co-sponsor and provided them with the addresses of customers within our service territory to directly mail the coupon books.

Whitby Hydro sent bill inserts to customers and displayed posters throughout the office and made coupon books available at the front desk. Customer Service staff and front line staff were trained to address questions about the EKC program and to deal with general enquiries about conservation and government incentives. Whitby Hydro also provided information at community events and with key retail outlets to review the program and to provide input on program marketing and presentment.

Lesson Learned:

- Customers who are interested in CDM activity are generally receptive to hearing about relevant programs offered by the OPA.
- Customers trust local distributors to provide useful information and are appreciative when distributors not only provide them with program offerings directly, but point them towards resources and information to take advantage of additional savings opportunities.
- Using promotional materials and events to market multiple programs is a cost effective approach.
- Having a primary contact (Conservation Officer) allows all available OPA programs and related communications to be passed on to the community in an effective manner.

OTHER CDM PROGRAMS

Whitby Hydro has also been involved in other types of CDM related activities/programs. These include a residential customer survey undertaken in 2006 as well as involvement in the Switch to Cold Campaign. Details of these efforts are outlined below.

You have the Power to Shape the Future:

Promotion Start May 1st 2006

Promotion Finish July 1st 2006

Introduction

In 2006 Whitby Hydro supported the "You have the Power to shape the future" program. It was a program designed to collect information on customer behaviour, which enabled a more focused effort for developing effective conservation programs to meet the needs of our customers.

Program Description

The program targeted residential customers and involved an online survey that collected information relating to their property size, energy requirements, age and type of appliances and other relevant information related to energy use. Whitby Hydro distributed over 35,000 inserts with the customer bills. In addition to the inserts a direct link to the survey was posted on the Whitby Hydro web site. Survey Results were used to identify target areas for future conservation programs.

Switch to Cold Campaign:

Promotion Start March 1 2007

Promotion Finish June 30, 2007

Introduction

The Switch to Cold Campaign was a campaign designed to encourage customers to use cold water when doing laundry. It was a mail campaign that provided customers with money saving coupons to purchase detergent that can be used with cold water. Logoed bill inserts included information outlining the benefits and cost savings of using cold water to do laundry.

Program Description

Marketing efforts began in January of 2007 when we ran the Switch to Cold Campaign which provided information on energy savings by using cold water when doing laundry. Bill inserts also included a $0.75 coupon for any Tide coldwater detergent. The program started in March 07 and coupons were distributed to 35,000 residential customers.

Customer Service staff were educated on the merits of the program and trained to handle calls concerning use of cold water when doing laundry

Attachment 10-1: Third Party Review

Burman Energy Consultants Group Inc.
98 Archibald Road • Kettleby, Ontario, L0G 1J0 • Phone: 1-877-662-5489 • Fax: 905-939-4606

Whitby Hydro Electric Corporation

LRAM Support

November 23, 2009

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., President

Table of Contents

1. Introduction

Whitby Hydro Electric Corporation (Whitby Hydro) initiated 19 Conservation and Demand Management (CDM) programs since Third Tranche CDM funding commenced in 2005, and augmented those local programs through direct support and involvement with Ontario Power Authority (OPA) provincial programs. By the end of 2008, Whitby Hydro had completed the CDM programs in the residential, commercial/industrial and infrastructure segments from its Third Tranche funding of $1.3 million. This commitment to CDM has returned energy savings of 9.06 million kWh and reduced peak demand by more than 1359 kW (as reported by Whitby Hydro in their 2008 CDM Annual Report).

With success in its CDM activities, Whitby Hydro has lost revenues that need to be addressed as part of its 2010 rates submission to the Ontario Energy Board (OEB). This process will ensure that future CDM investments are sustainable in the long term by becoming a standard element in future rate filings.

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) ("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 mechanism developed by the OEB to calculate lost revenue for savings is the Lost Revenue Adjustment Mechanism (LRAM).

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. Results from OEB-approved (third tranche) CDM programs, OPA CDM programs and Whitby Hydro funded programs represent the potential for lost revenue to the LDC, and will be included in calculations under LRAM.

The application for LRAM compensation that Whitby Hydro is considering as part of its 2010 rates filing is based on its 2006 to 2009 inclusive CDM results for programs completed as of December 2008, and represents a significant milestone in the LDC's CDM record.

2. Required

Whitby Hydro requested that Burman Energy Consultants Group Inc. (BECGI) review the LDC's preliminary LRAM assessment and supporting information and assist in producing finalized calculations and report suitable to support an LRAM claim as part of its 2010 rates submission. In completing the scope of work related to LRAM, BECGI committed to:

1. Review LRAM calculations and underlying data prepared by Whitby Hydro for annual year end CDM reports, and assess compliance with the CDM Guidelines, identifying variances and reconciliations.
2. Finalize LRAM calculations and assumptions consistent with CDM Guidelines and suitable for inclusion in Whitby Hydro's rates application, with supporting details.
3. Produce a report and recommendations related to LRAM findings.
4. In performing the above tasks, BECGI's involvement is intended to constitute a third party review as specified in the OEB's CDM Guidelines.

3. About LRAM

The OEB issued GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT, EB-2008-0037 were applied to the preparation of this LRAM application.

LRAM was calculated as the product of the demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to each respective class (net of Regulatory Asset Recovery rate riders). OPA sponsored program kW/kWhs are eligible for LRAM.

4. Methodology

To optimize the calculation of LRAM amounts, BECGI

1. Reviewed existing CDM Guidelines and precedents set through LDC submissions to the OEB, to identify the most prudent course for Whitby Hydro to complete its LRAM application.
2. Sought counsel within OEB staff to validate assumptions and processes to complete LRAM submissions consistent with other LDC submissions. Validation by each specific technology employed is included in the accompanying documentation.

3. Reviewed Whitby Hydro CDM program results, free ridership rates (see Attachment D), verified assumptions and calculations, identified variances with reported values, and recommended adjustments as appropriate to maintain consistency with the CDM Guidelines. Actual program results were provided by Whitby Hydro, including CDM Annual Reports, OPA program results reports, and supplemental information relevant to LRAM calculations.

4. Prepared report and recommendations related to LRAM calculations consistent with OEB CDM Guidelines.

5. Results

A review of LDC CDM programs with Whitby Hydro verified that documentation exists to support participation levels associated with the LRAM for Third Tranche and Whitby Hydro funded programs. The review process included reviewing the reports from Whitby's accounting system, copies of invoices, sign off sheets for seniors program and listing of community events attended.

The OPA has validated the results allocated to Whitby Hydro for OPA sponsored programs through Third Party Verification. Program results were confirmed to begin the year after program implementation.

The timing of results used in LRAM calculations for OPA sponsored programs are contained in the accompanying documentation under OPA Conservation Results, issued November 10, 2009.

The accompanying table below sets out the calculated amounts for LRAM for Whitby Hydro's Third Tranche and OPA CDM programming. The calculation of the results, by program and customer class as applicable, are explained in the text below, and detailed in the appended attachments.

Rate Class	LRAM $
Third Tranche	
RESIDENTIAL	$45,420.07
GENERAL SERVICE <50KW	$3,585.12
GENERAL SERVICE >50KW	$492.43
Whitby Hydro Funded Programs	
RESIDENTIAL	$4,670.65
OPA Programs	
RESIDENTIAL	$305,435.54
GENERAL SERVICE <50KW	$884.89
GENERAL SERVICE >50KW	$27,507.35
	$387,996.05

6. 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, for both Third Tranche and OPA CDM programs. No forecast or other adjustment for the effects of CDM programs was made to the load quantities used in the preparation of Whitby Hydro's rate cases in prior years. The entire actual load reduction achieved by the eligible Third Tranche CDM programs is subject to LRAM treatment. All results are net of free ridership. For all programs/projects, the most recently published OPA assumptions and measures list were used in LRAM calculations in accordance with OEB's direction letter, Conservation and Demand Management ("CDM") Input Assumptions Board File No.: EB-2008-0352, January 27, 2009 and consistent with recent Decision and Order EB-2009-0192 for Horizon Utilities Corporation that directed LRAM calculations use the most current available input assumptions for all CDM programs.

OPA sponsored programs also represent lost revenue through their successful implementation and are included in LRAM calculations. Lost revenue from results attributable to Whitby Hydro funded programs were also included in the LRAM calculations. Although not specifically addressed in the CDM Guidelines, this assessment was considered to be consistent with the CDM Guideline intention of removing the disincentive of eroding distributor revenues due to lower than forecast revenues.

The sum of all program LRAM calculations, including OPA sponsored programs is $387,996.05

Attachment A summarizes load impacts by class and program. Attachment B (Foregone Revenue By Class and Program) summarizes the CDM load impacts by program and rate class and the resultant revenue impacts.

7. Allocation and Manner of Recovery for LRAM Amounts

The LRAM amounts arising from CDM programs in each respective rate class are allocated to that class for recovery.

8. Recommendations

BECGI recommends the following:

1. LRAM amounts arising from CDM programs in each rate class be allocated to that class for recovery.

2. Incorporate impacts of CDM programming which occurred during the period 2005 to 2008 in future Cost of Service rate applications. This recognizes CDM as an established customer service element in the years ahead, with identifiable costs and benefits.

3. Use TRC/SSM calculation as one of the methods to assess the potential value of CDM programs considered for implementation.

4. Monitor savings attributed to 2009 OPA programs. LRAM calculations are based on results carried over from 2006 to 2008 OPA programs implemented only. This report did not consider any OPA programs implemented or operated during 2009, as the results for these programs will not be available until sometime in 2010.

ATTACHMENT A
CDM Load Impacts by Class and Program

Class / Program	Year Implemented	NET 2006 kWh	NET 2006 kW	GROSS 2006 kWh	GROSS 2006 kW	NET 2007 kWh	NET 2007 kW	GROSS 2007 kWh	GROSS 2007 kW	NET 2008 kWh	NET 2008 kW	GROSS 2008 kWh	GROSS 2008 kW	NET 2009 kWh	NET 2009 kW	GROSS 2009 kWh	GROSS 2009 kW	NET Total kWh	NET Total kW
Third Tranche																			
RESIDENTIAL																			
Education & Training	2006, 2007					234,330	5.42	260,366	6.03	554,934	12.85	616,594	14.27	554,934	12.85	616,594	14.27	1,344,198	31.12
Community Events	2006, 2007					116,640	2.70	129,600	3.00	720,641	16.68	800,712	16.98	720,641	16.68	800,712	18.54	1,557,922	36.06
Seniors Care Package	2006, 2007					107,902	1.47	117,301	1.64	158,448	2.16	172,253	2.40	158,448	2.16	172,253	2.40	424,797	5.80
GENERAL SERVICE <50KW																			
Seasonal Lighting	2006					66,228	0.00	69,713	0.00	66,228	0.00	69,713	0.00	66,228	0.00	69,713	0.00	198,683	0.00
GENERAL SERVICE >50KW																			
Durham Non Profit Housing	2006					232,841	48.78	289,546	60.82	232,841	48.78	289,546	60.82	232,841	48.78	289,546	60.82	698,522	146.33
Whitby Hydro Funded Programs																			
RESIDENTIAL																			
Seniors Program	2008													69,984	1.62	77,760	1.80	69,984	1.62
Low Income	2008													108,864	2.52	120,960	2.80	108,864	2.52
Community Events	2008													162,907	3.77	181,008	4.19	162,907	3.77
OPA Programs																			
RESIDENTIAL																			
Every Kilowatt Counts (spring)	2006	1,146,995	7.48	1,274,439	8.31	1,146,995	7.48	1,274,439	8.31	1,146,995	7.48	1,274,439	8.31	1,146,995	7.48	1,274,439	8.31	4,587,981	29.90
Cool Savings Rebate Program	2006, 2007, 2008	87,423	89.55	97,137	99.50	343,004	257.33	583,646	435.85	540,005	382.13	926,591	652.51	540,005	382.13	926,591	652.51	1,510,438	1111.13
Secondary Fridge Retirement Pilot	2006	46,957	10.64	52,174	11.83	46,957	10.64	52,174	11.83	46,957	10.64	52,174	11.83	46,957	10.64	52,174	11.83	187,828	42.57
Every Kilowatt Counts (fall)	2006	1,860,774	28.00	2,067,526	31.11	1,860,774	28.00	2,067,526	31.11	1,860,774	28.00	2,067,526	31.11	1,860,774	28.00	2,067,526	31.11	7,443,095	111.99
Great Refrigerator Roundup	2007, 2008					190,206	21.24	471,970	52.02	544,216	58.64	1,123,150	121.19	544,216	58.64	1,123,150	121.19	1,278,639	138.52
Aboriginal – Pilot	2007					0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Every Kilowatt Counts	2007					1,117,809	42.92	1,584,450	62.14	1,104,254	38.89	1,559,803	54.82	1,104,254	38.89	1,559,803	54.82	3,326,317	120.70
peaksaver®	2007, 2008					0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Summer Savings	2007					530,370	294.65	4,419,754	2,455.42	530,370	294.65	4,419,754	2,455.42	0	0.00	0	0.00	1,060,741	589.30
Affordable Housing – Pilot	2007					0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Social Housing – Pilot	2007					100,741	11.85	100,741	11.85	100,741	11.85	100,741	11.85	100,741	11.85	100,741	11.85	302,222	35.56
Energy Efficiency Assistance for Houses – Pilot	2007					0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Aboriginal	2008									0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Summer Sweepstakes	2008									373,889	94.97	479,345	121.75	134,919	54.46	172,973	69.82	508,808	149.42
Every Kilowatt Counts Power Savings Event	2008									1,011,717	55.17	2,509,217	132.14	1,007,316	52.72	2,496,674	125.16	2,019,033	107.90
Community Initiatives	2008													116,640	2.70	129,600	3.00	116,640	
GENERAL SERVICE <50KW																			
Toronto Comprehensive	2007, 2008					0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
High Performance New Construction	2008									1,779	2.11	2,542	3.01	1,779	2.11	2,542	3.01	3,559	4.22
Power Savings Blitz	2008									22,733	3.14	24,444	3.37	22,733	3.14	24,444	3.37	45,466	6.28
Chiller Plant Re-Commissioning	2008									0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
GENERAL SERVICE >50KW																			
Demand Response 1	2006, 2007, 2008	0	1735.47	0	1735.47	0	2054.14	0	2,054.14	0	2810.11	0	2,810.11	0	0.00	0	0.00	0	6599.72
Demand Response 3	2008									0	525.84	0	525.84	0	525.84	0	525.84	0	1051.68
Electricity Retrofit Incentive Program	2007, 2008					0	0.00	0	0.00	461,125	90.48	795,936	156.03	461,122	90.50	795,930	156.06	922,247	180.97
Other Demand Response	2007, 2008					0	163.67		163.67	0	181.00	0	181.00	0	0.00	0	0.00	0	344.67
		3,142,149	1,871	3,491,277	1,886	6,094,798	2,950	11,421,228	5,358	9,478,646	4,676	17,284,480	7,375	9,163,297	1,357	13,055,134	1,883	27,878,890	10,852

ATTACHMENT B
Foregone Revenue by Class and Program

Class Program	Year Implemented	2006				2007				2008				2009				Total Revenue	
		Load Unit	kWh or kW	Rate per Unit	Revenue	Load Unit	kWh or kW	Rate per Unit	Revenue	Load Unit	kWh or kW	Rate per Unit	Revenue	Load Unit	kWh or kW	Rate per Unit	Revenue		
Third Tranche																			
RESIDENTIAL																			
Education & Training	2006, 2007					234,330	kWh	0.0137	$3,202.51	554,934	kWh	0.0136	$7,565.60	554,934	kWh	0.0137	$7,584.10	$18,352.21	
Community Events	2006, 2007					116,640	kWh	0.0137	$1,594.08	720,641	kWh	0.0136	$9,824.74	720,641	kWh	0.0137	$9,848.76	$21,267.57	
Seniors Care Package	2006, 2007					107,902	kWh	0.0137	$1,474.67	158,448	kWh	0.0136	$2,160.17	158,448	kWh	0.0137	$2,165.45	$5,800.28	
																			$45,420.07
GENERAL SERVICE <50KW																			
Seasonal Lighting	2006					66,228	kWh	0.0181	$1,194.30	66,228	kWh	0.0180	$1,194.30	66,228	kWh	0.0181	$1,196.51	$3,585.12	
																			$3,585.12
GENERAL SERVICE >50KW																			
Durham Non Profit Housing	2006					48.78	kW	3.3730	$164.04	48.78	kW	3.3595	$164.09	48.78	kW	3.3729	$164.30	$492.43	
																			$492.43
Whitby Hydro Funded Programs																			
RESIDENTIAL																			
Seniors Program	2008													69,984	kWh	0.0137	$956.45	$956.45	
Low Income	2008													108,864	kWh	0.0137	$1,487.81	$1,487.81	
Community Events	2008													162,907	kWh	0.0137	$2,226.40	$2,226.40	
																			$4,670.65
OPA Programs																			
RESIDENTIAL																			
Every Kilowatt Counts (spring)	2006	1,146,995	kWh	0.0136	$15,799.86	1,146,995	kWh	0.0137	$15,675.60	1,146,995	kWh	0.0136	$15,637.37	1,146,995	kWh	0.0137	$15,675.60	$62,788.43	
Cool Savings Rebate Program	2006, 2007, 2008	87,423	kWh	0.0136	$1,204.25	343,004	kWh	0.0137	$4,687.73	540,005	kWh	0.0136	$7,362.07	540,005	kWh	0.0137	$7,380.07	$20,634.12	
Secondary Fridge Retirement Pilot	2006	46,957	kWh	0.0136	$646.83	46,957	kWh	0.0137	$641.74	46,957	kWh	0.0136	$640.18	46,957	kWh	0.0137	$641.74	$2,570.50	
Every Kilowatt Counts (fall)	2006	1,860,774	kWh	0.0136	$25,632.16	1,860,774	kWh	0.0137	$25,430.58	1,860,774	kWh	0.0136	$25,368.55	1,860,774	kWh	0.0137	$25,430.58	$101,861.86	
Great Refrigerator Roundup	2007, 2008					190,206	kWh	0.0137	$2,599.48	544,216	kWh	0.0136	$7,419.48	544,216	kWh	0.0137	$7,437.62	$17,456.59	
Aboriginal – Pilot	2007					0	kWh	0.0137	$0.00	0	kWh	0.0136	$0.00	0	kWh	0.0137	$0.00	$0.00	
Every Kilowatt Counts	2007					1,117,809	kWh	0.0137	$15,276.73	1,104,254	kWh	0.0136	$15,054.66	1,104,254	kWh	0.0137	$15,091.47	$45,422.85	
peaksaver®	2007, 2008					0	kWh	0.0137	$0.00	0	kWh	0.0136	$0.00	0	kWh	0.0137	$0.00	$0.00	
Summer Savings	2007					530,370	kWh	0.0137	$7,248.40	530,370	kWh	0.0136	$7,230.72	0	kWh	0.0137	$0.00	$14,479.11	
Affordable Housing – Pilot	2007					0	kWh	0.0137	$0.00	0	kWh	0.0136	$0.00	0	kWh	0.0137	$0.00	$0.00	
Social Housing – Pilot	2007					100,741	kWh	0.0137	$1,376.79	100,741	kWh	0.0136	$1,373.43	100,741	kWh	0.0137	$1,376.79	$4,127.01	
Energy Efficiency Assistance for Houses – Pilot	2007					0	kWh	0.0137	$0.00	0	kWh	0.0136	$0.00	0	kWh	0.0137	$0.00	$0.00	
Aboriginal	2008									0	kWh	0.0136	$0.00	0	kWh	0.0137	$0.00	$0.00	
Summer Sweepstakes	2008									373,889	kWh	0.0136	$5,097.35	134,919	kWh	0.0137	$1,843.89	$6,941.25	
Every Kilowatt Counts Power Savings Event	2008									1,011,717	kWh	0.0136	$13,793.08	1,007,316	kWh	0.0137	$13,766.65	$27,559.73	
Community Initiatives	2008													116,640	kWh	0.0137	$1,594.08	$1,594.08	
																			$305,435.54
GENERAL SERVICE <50KW																			
Toronto Comprehensive	2007, 2008					0.00	kWh	0.0181	$0.00	0	kWh	0.0180	$0.00	0	kWh	0.0181	$0.00	$0.00	
High Performance New Construction	2008									1,779	kWh	0.0180	$32.09	1,779	kWh	0.0181	$32.15	$64.23	
Power Savings Blitz	2008									22,733	kWh	0.0180	$409.95	22,733	kWh	0.0181	$410.71	$820.65	
Chiller Plant Re-Commissioning	2008									0	kWh	0.0180	$0.00	0	kWh	0.0181	$0.00	$0.00	
																			$884.89
GENERAL SERVICE >50KW																			
Demand Response 1	2006, 2007, 2008	1735.47	kW	3.3429	$5,837.48	2054.14	kW	3.3730	$6,908.00	2810.11	kW	3.3595	$9,453.21	0.00	kW	3.3729	$0.00	$22,198.69	
Demand Response 3	2008									525.84	kW	3.3595	$1,768.92	525.84	kW	3.3729	$1,771.25	$3,540.17	
Electricity Retrofit Incentive Program	2007, 2008					0.00	kW	3.3730	$0.00	90.48	kW	3.3595	$304.37	90.50	kW	3.3729	$304.83	$609.19	
Other Demand Response	2007, 2008					163.67	kW	3.3730	$550.43	181.00	kW	3.3595	$608.87	0.00	kW	3.3729	$0.00	$1,159.30	
																			$27,507.35
																			$387,996.05

ATTACHMENT C

LRAM Totals

Rate Class

	LRAM $
Third Tranche	
RESIDENTIAL	$45,420.07
GENERAL SERVICE <50KW	$3,585.12
GENERAL SERVICE >50KW	$492.43
Whitby Hydro Funded Programs	
RESIDENTIAL	$4,670.65
OPA Programs	
RESIDENTIAL	$305,435.54
GENERAL SERVICE <50KW	$884.89
GENERAL SERVICE >50KW	$27,507.35
	$387,996.05

ATTACHMENT D

Free Ridership Rates by Program & Technology

2006	
Education & Training	
CLF Give Away - 13W	10%
Community Events	
CLF Give Away - 13W	10%
Seniors Care Package	
CLF Give Away - 13W	10%
Seasonal LED Lights - 5W	5%
Seasonal Lighting	
Seasonal LED - 5W	5%
Seasonal LED Lights - Mini Lights	5%
Durham Non-Profit Housing (DNPH)	
Lighting Upgrade - 13W	10%
Energy Star Fridges	10%
Lighting Upgrade - 1Lamp T8 32W	10%
Lighting Upgrade - 2Lamp T8 32W	10%
Lighting Upgrade - 4Lamp T8 32W	10%
2007	
Education & Training	
CLF Give Away - 13W	10%
Community Events	
CLF Give Away - 13W	10%
Seniors Care Package	
CLF Give Away - 13W	10%
Seasonal LED Lights - 5W	5%
2008	
Community Events	
CLF Give Away - 13W	10%
Seniors Program	
Light Bulb Exchange - 13W	10%
Low Income	
CFL Distribution 13W	10%

Attachment E
Assumptions by program

Program:	**Education & Training**
	Third Tranche Program
Description:	CFL Give Away - 13W
OPA Table Applied:	Residential
Number of Units:	6,027
Start Year:	2006
Incremental Costs:	$10,848.60
Discount Factor:	6.82%
LDC Costs:	$33,168.00
	LRAM
Element No.:	24
EE Technology Life:	8
Free Ridership Rate:	10%

Attachment E
Assumptions by program

Program:	**Education & Training**
	Third Tranche Program
Description:	CFL Give Away - 13W
OPA Table Applied:	Residential
Number of Units:	8,246
Start Year:	2007
Incremental Costs:	$14,842.80
Discount Factor:	6.82%
LDC Costs:	$25,695.00
	LRAM
Element No.:	24
EE Technology Life:	8
Free Ridership Rate:	10%

Attachment E
Assumptions by program

Program:	Community Events
	Third Tranche Program
Description:	CFL Give Away - 13W
OPA Table Applied:	Residential
Number of Units:	3000
Start Year:	2006
Incremental Costs:	$5,400.00
Discount Factor:	6.82%
LDC Costs:	$7,309.00
	LRAM
Element No.:	24
EE Technology Life:	8
Free Ridership Rate:	10%

Attachment E
Assumptions by program

Program:	Community Events	
	Third Tranche Program	
Description:	CFL Give Away - 13W	
OPA Table Applied:	Residential	
Number of Units:	15535	
Start Year:	2007	
Incremental Costs:	$27,963.00	
Discount Factor:	6.82%	
LDC Costs:	$28,937.00	
	LRAM	
Element No.:	24	
EE Technology Life:	8	
Free Ridership Rate:	10%	

Attachment E

Assumptions by program

Program:	**Seniors Care Package**		
	Third Tranche Program		
Description:	CFL Give Away - 13W	Seasonal LED Lights - 5W Lights	Summary TRC
OPA Table Applied:	Residential	Residential	
Number of Units:	1636	818	
Start Year:	2006	2006	
Incremental Costs:	$2,944.80	$1,554.20	$4,499.00
Discount Factor:	6.82%	6.82%	6.82%
LDC Costs:			$14,371.00
	LRAM	LRAM	
Element No.:	24	35	
EE Technology Life:	8	30	
Free Ridership Rate:	10%	5%	

Attachment E

Assumptions by program

Program:	**Seniors Care Package**		
	Third Tranche Program		
Description:	CFL Give Away - 13W	2007 Seasonal LED Lights - 5W	Summary TRC
OPA Table Applied:	Residential	Residential	
Number of Units:	768	382	
Start Year:	2007	2007	
Incremental Costs:	$1,382.40	$725.80	$2,108.20
Discount Factor:	6.82%	6.82%	
LDC Costs:			$10,476.00
	LRAM	LRAM	
Element No.:	24	35	
EE Technology Life:	8	30	
Free Ridership Rate:	10%	5%	

Attachment E

Assumptions by program

Program:	**Seasonal Lighting**		
	Third Tranche Program		
Description:	Seasonal LED - 5W	Seasonal LED Lights - Mini Lights	Summary TRC
OPA Table Applied:	Residential	Residential	
Number of Units:	1220	24	
Start Year:	2006	2006	
Incremental Costs:	$2,318.00	$45.60	$2,363.60
Discount Factor:	6.82%	6.82%	
LDC Costs:			$8,537.00
	LRAM	LRAM	
Element No.:	35	36	
EE Technology Life:	30	30	
Free Ridership Rate:	5%	5%	

Attachment E
Assumptions by program

Program:	Durham Non-Profit Housing (DNPH)					
	Third Tranche Program					
Description:	Lighting Upgrade - 13W CFL	Replace Standard Fridges with Energy Star Fridges	Lighting Upgrade - 1Lamp T8 32W	Lighting Upgrade - 2Lamp T8 32W	Lighting Upgrade - 4Lamp T8 32W	Summary TRC
OPA Table Applied:	Commercial	Residential	Commercial	Commercial	Commercial	
Number of Units:	274	175	444	278	64	
Start Year:	2006	2006	2006	2006	2006	
Incremental Costs:	$1,726.20	$11,025.00	$14,185.80	$13,135.50	$3,744.00	$43,816.50
Discount Factor:	6.82%	6.82%	6.82%	6.82%	6.82%	6.82%
LDC Costs:						
	LRAM	LRAM	LRAM	LRAM	LRAM	
Element No.:	8	2	3	1	2	
EE Technology Life:	24	19	5	5	5	
Free Ridership Rate:	10%	10%	10%	10%	10%	

Attachment E
Assumptions by program

Program:	**Seniors Program**
	Whitby Hydro Funded Program
Description:	Light bulb exchange program. 60W to 13W
OPA Table Applied:	Residential
Number of Units:	1800
Start Year:	2008
Incremental Costs:	$3,240.00
Discount Factor:	6.67%
LDC Costs:	$10,211.00
	LRAM
Element No.:	24
EE Technology Life:	8
Free Ridership Rate:	10%

Attachment E
Assumptions by program

Program:	**Low Income**
	Whitby Hydro Funded Program
Description:	CFLs Distribution 60W to 13W
OPA Table Applied:	Residential
Number of Units:	2800
Start Year:	2008
Incremental Costs:	$5,040.00
Discount Factor:	6.67%
LDC Costs:	$10,331.00
	LRAM
Element No.:	24
EE Technology Life:	8
Free Ridership Rate:	10%

Attachment E
Assumptions by program

Program:	**Community Events**
	Whitby Hydro Funded Program
Description:	CFL Distribution - 60W to 13W
OPA Table Applied:	Residential
Number of Units:	4190
Start Year:	2008
Incremental Costs:	$7,542.00
Discount Factor:	6.67%
LDC Costs:	$18,939.00
	LRAM
Element No.:	24
EE Technology Life:	8
Free Ridership Rate:	10%

Attachment E
Assumptions by program

Program:	**Community Initiatives**
	OPA Funded Program
Description:	13W CFL
OPA Table Applied:	Residential
Number of Units:	3000
Start Year:	2008
Incremental Costs:	$5,400.00
Discount Factor:	6.67%
LDC Costs:	
	LRAM
Element No.:	24
EE Technology Life:	8
Free Ridership Rate:	10%

Appendix A

2006-2008 OPA Conservation Results

OPA Conservation & Demand Management Programs

Annual Results

For: Whitby Hydro Electric Corporation

#	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	Whitby Hydro Electric Corporation	2006	Final	1.87	1.87	1.87	0.14	0.14	0.13	0.12	0.09
2	Whitby Hydro Electric Corporation	2007	Final	0.00	1.02	1.02	0.24	0.24	0.24	0.23	0.23
3	Whitby Hydro Electric Corporation	2008	Final	0.00	0.00	1.71	0.89	0.89	0.89	0.89	0.36
Total				2	3	5	1	1	1	1	1
4	Province Wide	2006	Final	282.17	282.17	282.17	16.17	16.17	15.27	14.01	10.67
5	Province Wide	2007	Final	0.00	300.38	299.91	177.11	177.11	176.15	42.13	42.13
6	Province Wide	2008	Final	0.00	0.00	360.73	179.37	179.27	179.27	178.59	93.59
Total				282	583	943	373	373	371	235	146

#	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	Whitby Hydro Electric Corporation	2006	Final	3,142	3,142	3,142	3,142	3,142	1,995	1,948	87
2	Whitby Hydro Electric Corporation	2007	Final	0	2,195	2,181	1,651	1,651	1,651	1,594	1,594
3	Whitby Hydro Electric Corporation	2008	Final	0	0	2,425	2,181	2,176	2,176	2,024	2,024
Total				3,142	5,337	7,748	6,974	6,969	5,822	5,566	3,705
4	Province Wide	2006	Final	374,407	374,407	374,407	374,407	374,407	237,735	232,140	10,417
5	Province Wide	2007	Final	0	474,318	472,717	391,717	391,717	371,920	199,587	194,587
6	Province Wide	2008	Final	0	0	360,162	335,617	334,553	334,553	316,559	316,378
Total				374,407	848,725	1,207,285	1,101,741	1,100,677	944,208	748,286	521,382

#	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	Whitby Hydro Electric Corporation	2006	Final	1.89	1.89	1.89	0.15	0.15	0.14	0.13	0.10
2	Whitby Hydro Electric Corporation	2007	Final	0.00	3.40	3.39	0.46	0.46	0.46	0.39	0.39
3	Whitby Hydro Electric Corporation	2008	Final	0.00	0.00	2.00	1.17	1.17	1.17	1.16	0.63
Total				2	5	7	2	2	2	2	1
4	Province Wide	2006	Final	283.96	283.96	283.96	17.96	17.96	16.97	15.56	11.86
5	Province Wide	2007	Final	0.00	671.04	670.17	217.37	217.37	216.41	61.34	61.34
6	Province Wide	2008	Final	0.00	0.00	405.15	222.12	221.99	221.99	220.21	135.21
Total				284	955	1,359	457	457	455	297	208

#	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013
1	Whitby Hydro Electric Corporation	2006	Final	3,491	3,491	3,491	3,491	3,491	2,217	2,165	97
2	Whitby Hydro Electric Corporation	2007	Final	0	7,063	7,039	2,619	2,619	2,619	2,403	2,403
3	Whitby Hydro Electric Corporation	2008	Final	0	0	4,808	4,489	4,484	4,484	4,088	4,088
Total				3,491	10,555	15,338	10,599	10,594	9,320	8,656	6,588
4	Province Wide	2006	Final	416,007	416,007	416,007	416,007	416,007	264,150	257,933	11,574
5	Province Wide	2007	Final	0	1,189,858	1,186,946	511,946	511,946	492,149	277,077	277,077
6	Province Wide	2008	Final	0	0	677,605	645,319	643,918	643,918	597,241	596,982
Total				416,007	1,605,865	2,280,559	1,573,273	1,571,872	1,400,217	1,132,252	885,634

Annual Results Continued

#	Program Name	Program Year	Results Status	Net Summer Peak Demand Savings (MW)							
				2014	2015	2016	2017	2018	2019	2020	2021
1	Whitby Hydro Electric Corporation	2006	Final	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00
2	Whitby Hydro Electric Corporation	2007	Final	0.23	0.19	0.18	0.16	0.16	0.16	0.16	0.16
3	Whitby Hydro Electric Corporation	2008	Final	0.35	0.35	0.33	0.29	0.29	0.29	0.28	0.28
Total				1	1	1	1	1	0	0	0
4	Province Wide	2006	Final	10.67	10.67	10.67	10.67	10.67	0.00	0.00	0.00
5	Province Wide	2007	Final	42.13	38.33	37.30	34.83	34.83	21.50	21.50	21.19
6	Province Wide	2008	Final	92.29	91.85	87.72	80.98	80.63	80.63	79.52	45.40
Total				145	141	136	126	126	102	101	67

#	Program Name	Program Year	Results Status	Net Annual Energy Savings (MWh)							
				2014	2015	2016	2017	2018	2019	2020	2021
1	Whitby Hydro Electric Corporation	2006	Final	87	87	87	87	87	0	0	0
2	Whitby Hydro Electric Corporation	2007	Final	1,594	582	433	263	263	263	263	263
3	Whitby Hydro Electric Corporation	2008	Final	1,865	1,747	1,366	1,077	994	994	979	972
Total				3,547	2,416	1,887	1,427	1,344	1,257	1,242	1,235
4	Province Wide	2006	Final	10,417	10,417	10,417	10,417	10,417	0	0	0
5	Province Wide	2007	Final	194,587	77,277	66,358	46,225	46,225	46,225	46,225	41,971
6	Province Wide	2008	Final	297,758	283,825	236,654	196,624	187,191	187,191	184,705	183,376
Total				502,761	371,519	313,429	253,265	243,833	233,416	230,930	225,346

#	Program Name	Program Year	Results Status	Gross Summer Peak Demand Savings (MW)							
				2014	2015	2016	2017	2018	2019	2020	2021
1	Whitby Hydro Electric Corporation	2006	Final	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00
2	Whitby Hydro Electric Corporation	2007	Final	0.39	0.34	0.30	0.28	0.28	0.28	0.28	0.28
3	Whitby Hydro Electric Corporation	2008	Final	0.61	0.60	0.56	0.50	0.49	0.49	0.47	0.47
Total				1	1	1	1	1	1	1	1
4	Province Wide	2006	Final	11.86	11.86	11.86	11.86	11.86	0.00	0.00	0.00
5	Province Wide	2007	Final	61.34	56.15	53.51	50.18	50.18	35.37	35.37	35.06
6	Province Wide	2008	Final	132.38	131.21	124.38	111.36	110.59	110.59	108.10	70.18
Total				206	199	190	173	173	146	143	105

#	Program Name	Program Year	Results Status	Gross Annual Energy Savings (MWh)							
				2014	2015	2016	2017	2018	2019	2020	2021
1	Whitby Hydro Electric Corporation	2006	Final	97	97	97	97	97	0	0	0
2	Whitby Hydro Electric Corporation	2007	Final	2,403	1,064	683	458	458	458	458	458
3	Whitby Hydro Electric Corporation	2008	Final	3,733	3,417	2,734	2,205	2,029	2,029	1,994	1,986
Total				6,234	4,578	3,514	2,760	2,584	2,487	2,452	2,444
4	Province Wide	2006	Final	11,574	11,574	11,574	11,574	11,574	0	0	0
5	Province Wide	2007	Final	277,077	123,786	95,856	69,231	69,231	69,231	69,231	64,977
6	Province Wide	2008	Final	555,334	518,183	434,492	359,600	339,246	339,246	334,040	332,452
Total				843,986	653,544	541,923	440,405	420,052	408,477	403,271	397,429

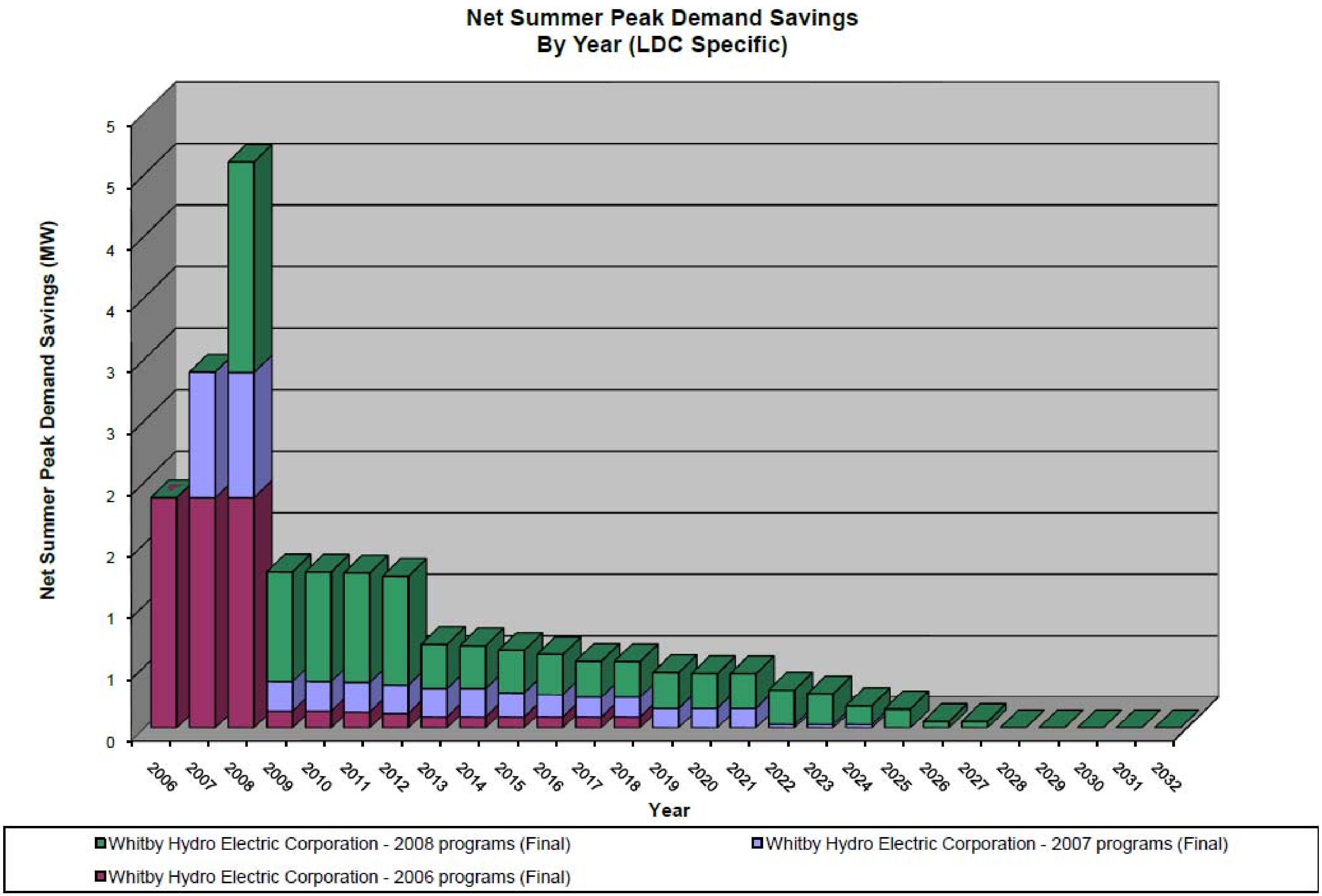
Annual Results Continued

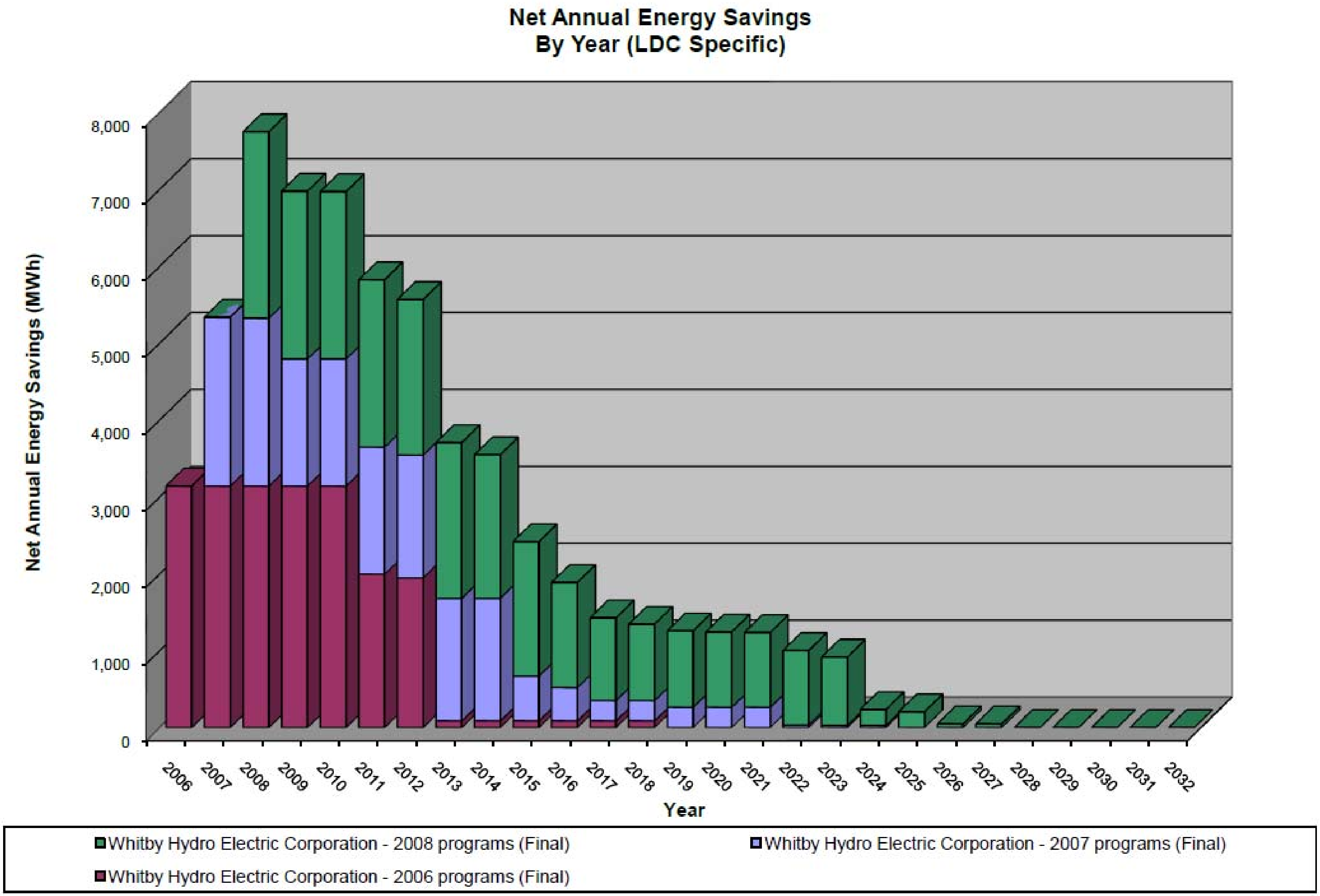
#	Program Name	Program Year	Results Status	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Whitby Hydro Electric Corporation	2006	Final	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Whitby Hydro Electric Corporation	2007	Final	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Whitby Hydro Electric Corporation	2008	Final	0.28	0.25	0.15	0.15	0.05	0.05	0.00	0.00	0.00	0.00	0.00
Total				0	0	0	0	0	0	0	0	0	0	0
4	Province Wide	2006	Final	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	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	Final	45.03	41.23	26.42	26.42	14.41	14.41	0.00	0.00	0.00	0.00	0.00
Total				51	47	32	29	16	14	0	0	0	0	0

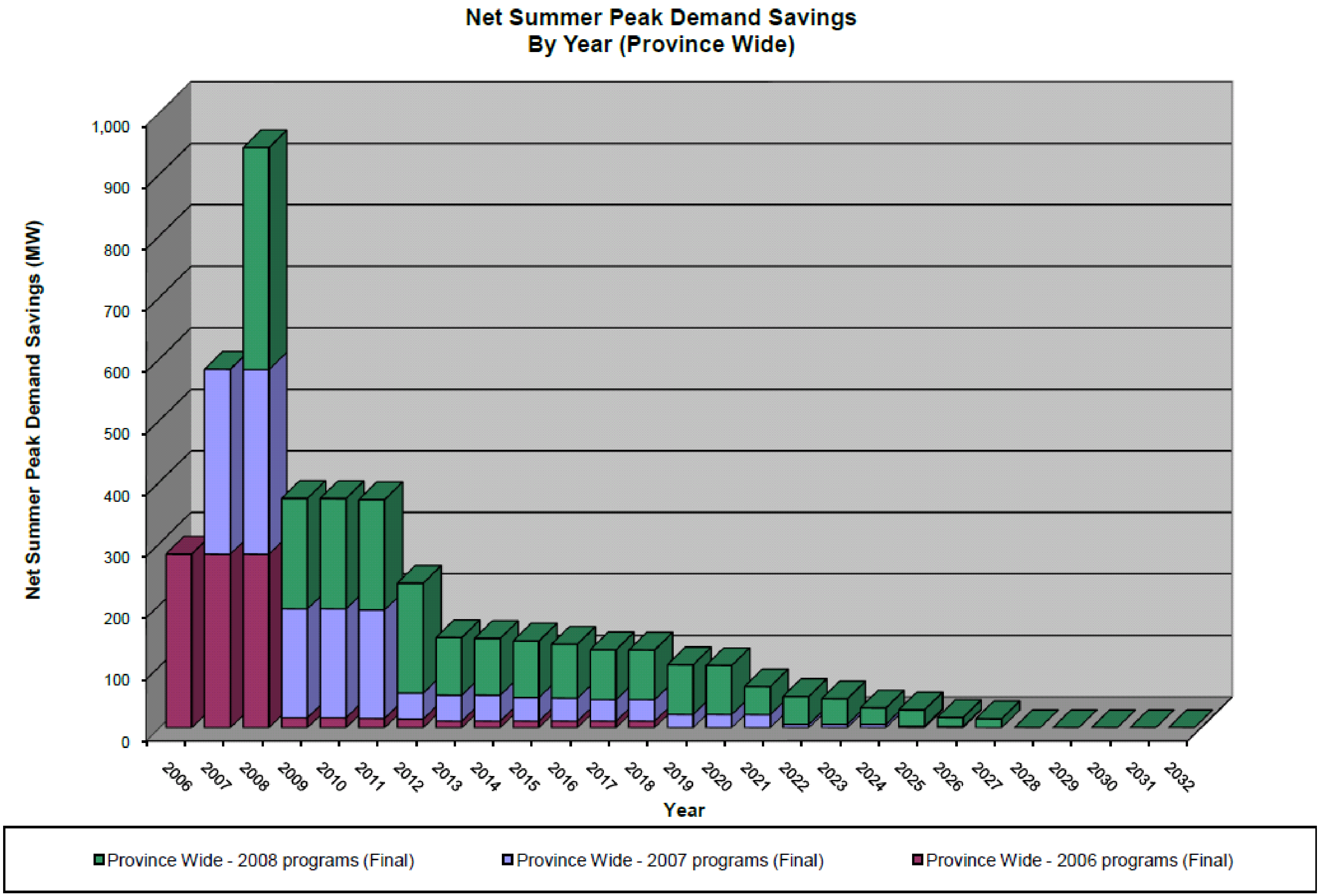
#	Program Name	Program Year	Results Status	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Whitby Hydro Electric Corporation	2006	Final	0	0	0	0	0	0	0	0	0	0	0
2	Whitby Hydro Electric Corporation	2007	Final	34	29	29	0	0	0	0	0	0	0	0
3	Whitby Hydro Electric Corporation	2008	Final	968	887	204	204	47	47	0	0	0	0	0
Total				1,002	916	233	204	47	47	0	0	0	0	0
4	Province Wide	2006	Final	0	0	0	0	0	0	0	0	0	0	0
5	Province Wide	2007	Final	14,937	14,313	14,313	10,907	8,607	0	0	0	0	0	0
6	Province Wide	2008	Final	182,857	171,903	59,667	59,667	41,012	41,012	0	0	0	0	0
Total				197,794	186,216	73,980	70,574	49,619	41,012	0	0	0	0	0

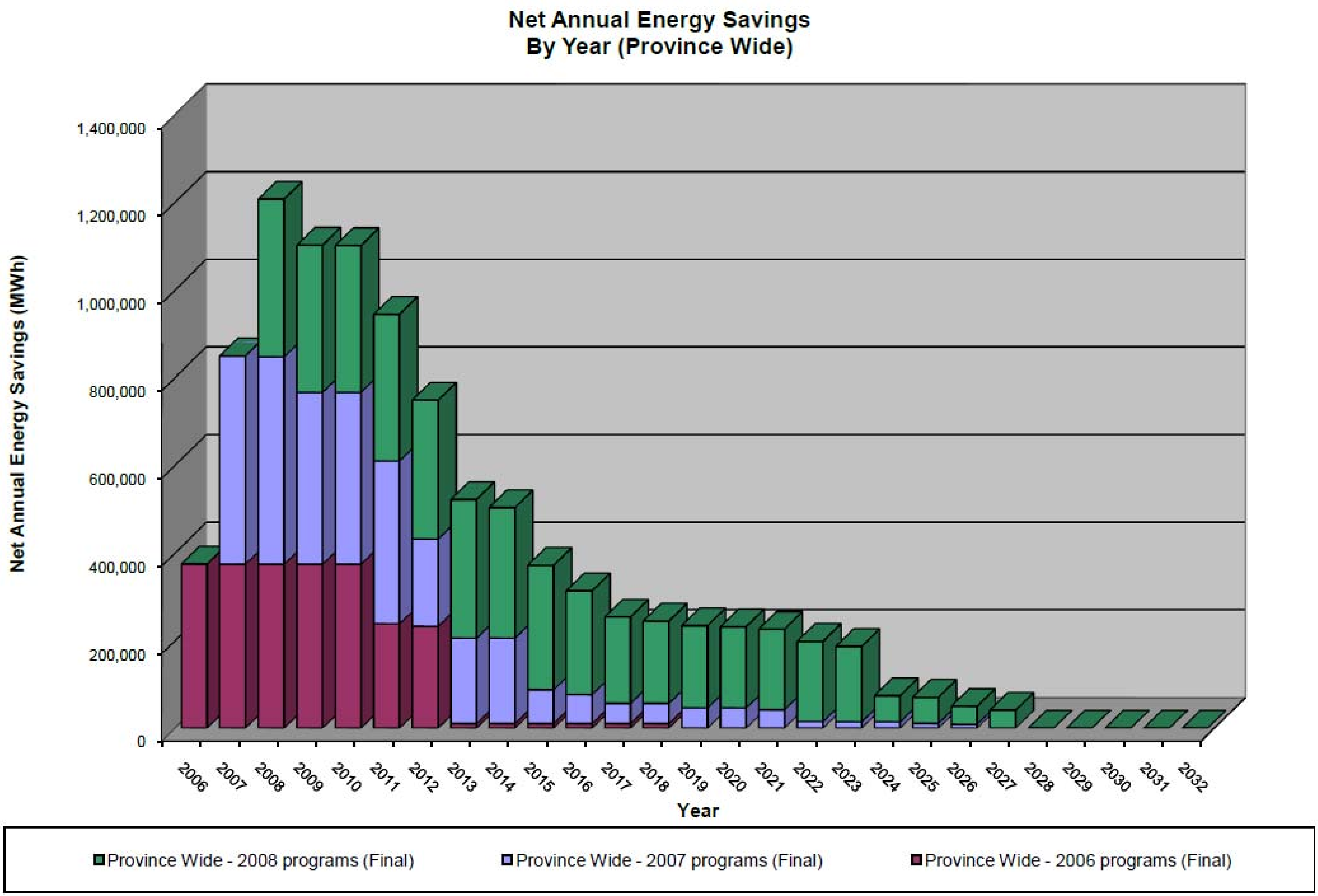
#	Program Name	Program Year	Results Status	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Whitby Hydro Electric Corporation	2006	Final	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Whitby Hydro Electric Corporation	2007	Final	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Whitby Hydro Electric Corporation	2008	Final	0.47	0.41	0.24	0.24	0.06	0.06	0.00	0.00	0.00	0.00	0.00
Total				1	0	0	0	0	0	0	0	0	0	0
4	Province Wide	2006	Final	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	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	Final	69.66	63.43	36.95	36.95	16.08	16.08	0.00	0.00	0.00	0.00	0.00
Total				78	71	45	39	18	16	0	0	0	0	0

#	Program Name	Program Year	Results Status	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1	Whitby Hydro Electric Corporation	2006	Final	0	0	0	0	0	0	0	0	0	0	0
2	Whitby Hydro Electric Corporation	2007	Final	58	48	48	0	0	0	0	0	0	0	0
3	Whitby Hydro Electric Corporation	2008	Final	1,980	1,847	334	334	60	60	0	0	0	0	0
Total				2,038	1,895	382	334	60	60	0	0	0	0	0
4	Province Wide	2006	Final	0	0	0	0	0	0	0	0	0	0	0
5	Province Wide	2007	Final	17,763	16,629	16,629	10,907	8,607	0	0	0	0	0	0
6	Province Wide	2008	Final	331,746	313,985	79,645	79,645	47,148	47,148	0	0	0	0	0
Total				349,509	330,614	96,274	90,551	55,754	47,148	0	0	0	0	0


Net Summer Peak Demand Savings
By Year (LDC Specific)
Net Summer Peak Demand Savings (MW)
5
5
4
4
3
3
2
2
1
1
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
Whitby Hydro Electric Corporation - 2008 programs (Final)
Whitby Hydro Electric Corporation - 2007 programs (Final)
Whitby Hydro Electric Corporation - 2006 programs (Final)


Net Annual Energy Savings
By Year (LDC Specific)
Net Annual Energy Savings (MWh)
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
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
Whitby Hydro Electric Corporation - 2008 programs (Final)
Whitby Hydro Electric Corporation - 2007 programs (Final)
Whitby Hydro Electric Corporation - 2006 programs (Final)


Net Summer Peak Demand Savings
By Year (Province Wide)
Net Summer Peak Demand Savings (MW)
1,000
900
800
700
600
500
400
300
200
100
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 (Final)
Province Wide - 2007 programs (Final)
Province Wide - 2006 programs (Final)


Net Annual Energy Savings
By Year (Province Wide)
Net Annual Energy Savings (MWh)
1,400,000
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 (Final)
Province Wide - 2007 programs (Final)
Province Wide - 2006 programs (Final)

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2006	2007	2008	2009	2010	2011	2012
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	0.01	0.00	0.00
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.09	0.09	0.09	0.09	0.09	0.09	0.09
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
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.03	0.03	0.03	0.03	0.03	0.03	0.03
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	1.74	1.74	1.74	0.00	0.00	0.00	0.00
2006 Subtotal						**1.87**	**1.87**	**1.87**	**0.14**	**0.14**	**0.13**	**0.12**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0.00	0.02	0.02	0.02	0.02	0.02	0.02
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	0.16
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.04	0.04	0.04	0.04	0.04	0.04
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	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	0.29	0.29	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
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
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
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0.00	0.32	0.32	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	0.16	0.16	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
2007 Subtotal						**0.00**	**1.02**	**1.02**	**0.24**	**0.24**	**0.24**	**0.23**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.00	0.00	0.04	0.04	0.04	0.04	0.04
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.12	0.12	0.12	0.12	0.12
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.00	0.00	0.09	0.05	0.05	0.05	0.05
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.06	0.05	0.05	0.05	0.05
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.00	0.00	0.09	0.09	0.09	0.09	0.09
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.76	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.53	0.53	0.53	0.53	0.53
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.02	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	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	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0.00**	**0.00**	**1.71**	**0.89**	**0.89**	**0.89**	**0.89**
Overall Total						**1.87**	**2.89**	**4.60**	**1.27**	**1.27**	**1.26**	**1.23**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2013	2014	2015	2016	2017	2018	2019
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
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.09	0.09	0.09	0.09	0.09	0.09	0.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.00**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0.02	0.02	0.01	0.00	0.00	0.00	0.00
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.16	0.16	0.16	0.16	0.16	0.16	0.16
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.04	0.04	0.01	0.01	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
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	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
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	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
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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	0.00	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
2007 Subtotal						**0.23**	**0.23**	**0.19**	**0.18**	**0.16**	**0.16**	**0.16**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.04	0.04	0.04	0.03	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.12	0.12	0.12	0.12	0.12	0.12	0.12
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.05	0.05	0.05	0.05	0.05	0.05	0.05
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.05	0.04	0.03	0.02	0.02	0.02	0.02
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.09	0.09	0.09	0.09	0.09	0.09	0.09
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	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	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0.36**	**0.35**	**0.35**	**0.33**	**0.29**	**0.29**	**0.29**
Overall Total						**0.68**	**0.67**	**0.63**	**0.60**	**0.54**	**0.54**	**0.45**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Summer Peak Demand Savings (2020	2021	2022	2023	2024	2025	2026	2027
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
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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	0.00	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	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	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	0.16	0.16	0.03	0.03	0.03	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.00	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
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	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
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	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
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
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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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	0.00	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
2007 Subtotal						**0.16**	**0.16**	**0.03**	**0.03**	**0.03**	**0.00**	**0.00**	**0.00**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.12	0.12	0.12	0.10	0.10	0.10	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	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	Final	LDC Participation	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	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0.28**	**0.28**	**0.28**	**0.25**	**0.15**	**0.15**	**0.05**	**0.05**
Overall Total						**0.44**	**0.44**	**0.31**	**0.27**	**0.18**	**0.15**	**0.05**	**0.05**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Summer Peak Demand Savings (MW) 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
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	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	0.00	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.00	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
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	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
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	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
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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	0.00	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
2007 Subtotal						**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Overall Total						**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2006	2007	2008	2009	2010	2011	2012
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	1,147	1,147	1,147	1,147	1,147	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	87	87	87	87	87	87	87
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	47	47	47	47	47	47	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	1,861	1,861	1,861	1,861	1,861	1,861	1,861
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
2006 Subtotal						**3,142**	**3,142**	**3,142**	**3,142**	**3,142**	**1,995**	**1,948**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	190	190	190	190	190	189
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	256	256	256	256	256	247
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	1,118	1,104	1,104	1,104	1,104	1,057
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	530	530	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	101	101	101	101	101	101
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0	0
2007 Subtotal						**0**	**2,195**	**2,181**	**1,651**	**1,651**	**1,651**	**1,594**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	354	354	354	354	354
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	197	197	197	197	197
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0	0	374	135	135	135	135
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	1,012	1,007	1,007	1,007	855
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0	0	461	461	461	461	461
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	2	2	2	2	2
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0	0	23	23	18	18	18
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	2	2	2	2	2
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
2008 Subtotal						**0**	**0**	**2,425**	**2,181**	**2,176**	**2,176**	**2,024**
Overall Total						**3,142**	**5,337**	**7,748**	**6,974**	**6,969**	**5,822**	**5,566**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2013	2014	2015	2016	2017	2018	2019
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	87	87	87	87	87	87	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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
2006 Subtotal						**87**	**87**	**87**	**87**	**87**	**87**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	189	189	149	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	247	247	247	247	247	247	247
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	1,057	1,057	86	86	16	16	16
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	101	101	101	101	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0	0
2007 Subtotal						**1,594**	**1,594**	**582**	**433**	**263**	**263**	**263**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	354	354	354	285	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	197	197	197	197	197	197	197
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	135	135	135	74	74	56	56
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	855	696	578	365	360	295	295
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	461	461	461	424	424	424	424
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	2	2	2	2	2	2	2
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	18	18	18	18	18	18	18
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	2	2	2	2	2	2	2
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
2008 Subtotal						**2,024**	**1,865**	**1,747**	**1,366**	**1,077**	**994**	**994**
Overall Total						**3,705**	**3,547**	**2,416**	**1,887**	**1,427**	**1,344**	**1,257**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Annual Energy Savings (M 2021	2022	2023	2024	2025	2026	2027
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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
2006 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	247	24	24	24	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	16	10	4	4	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0	0
2007 Subtotal						**263**	**34**	**29**	**29**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	197	197	157	157	157	0	0
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	50	47	45	45	45	45	45
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	280	280	270	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	424	424	411	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	2	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	18	18	2	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	2	2	2	2	2	2	2
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
2008 Subtotal						**972**	**968**	**887**	**204**	**204**	**47**	**47**
Overall Total						**1,235**	**1,002**	**916**	**233**	**204**	**47**	**47**

OPA Conservation & Demand Management Programs
Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Annual Energy Savings (MWh) 2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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
2006 Subtotal						**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0
9	2007 Aboriginal - Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	0	0	0	0
13	2007 Affordable Housing - Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0
14	2007 Social Housing - Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses - Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	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
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
2007 Subtotal						**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0
2008 Subtotal						**0**	**0**	**0**	**0**	**0**
Overall Total						**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2006	2007	2008	2009	2010	2011	2012
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	0.01	0.00	0.00
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.10	0.10	0.10	0.10	0.10	0.10	0.10
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
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.03	0.03	0.03	0.03	0.03	0.03	0.03
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	1.74	1.74	1.74	0.00	0.00	0.00	0.00
2006 Subtotal						2	2	2	0	0	0	0
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0.00	0.05	0.05	0.05	0.05	0.05	0.05
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.00	0.34	0.34	0.34	0.34	0.34	0.28
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.06	0.05	0.05	0.05	0.05	0.05
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	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	2.46	2.46	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
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
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
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0.00	0.32	0.32	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	0.16	0.16	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
2007 Subtotal						0	3	3	0	0	0	0
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.00	0.00	0.07	0.07	0.07	0.07	0.07
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.22	0.22	0.22	0.22	0.22
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.00	0.00	0.12	0.07	0.07	0.07	0.07
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.13	0.13	0.13	0.13	0.11
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.00	0.00	0.16	0.16	0.16	0.16	0.16
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.76	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.53	0.53	0.53	0.53	0.53
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.02	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	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	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						0	0	2	1	1	1	1
Overall Total						2	5	7	2	2	2	2

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2013	2014	2015	2016	2017	2018	2019
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
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.10	0.10	0.10	0.10	0.10	0.10	0.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0.05	0.05	0.04	0.00	0.00	0.00	0.00
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.28	0.28	0.28	0.28	0.28	0.28	0.28
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.05	0.05	0.02	0.02	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
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	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
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0.01	0.01	0.01	0.01	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
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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	0.00	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
2007 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.07	0.07	0.07	0.05	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.22	0.22	0.22	0.22	0.22	0.22	0.22
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.07	0.07	0.07	0.07	0.07	0.07	0.07
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.11	0.09	0.08	0.06	0.05	0.05	0.05
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.16	0.16	0.16	0.15	0.15	0.15	0.15
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	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	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**1**	**1**	**1**	**1**	**0**	**0**	**0**
Overall Total						**1**	**1**	**1**	**1**	**1**	**1**	**1**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Gross							
						Summer Peak Demand Savings (							
						2020	2021	2022	2023	2024	2025	2026	2027
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
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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	0.00	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	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	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	0.28	0.28	0.05	0.05	0.05	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.00	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
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	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
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	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
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
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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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	0.00	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
2007 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.22	0.22	0.22	0.18	0.18	0.18	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	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	Final	LDC Participation	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	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Overall Total						**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs
Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Gross Summer Peak Demand Savings (MW) 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
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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	0.00	0.00	0.00	0.00	0.00
2006 Subtotal						**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	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	0.00	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	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	0.00	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
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	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
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	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
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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	0.00	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
2007 Subtotal						**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0.00	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0.00	0.00	0.00	0.00	0.00
2008 Subtotal						**0**	**0**	**0**	**0**	**0**
Overall Total						**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2006	2007	2008	2009	2010	2011
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	1,274	1,274	1,274	1,274	1,274	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	97	97	97	97	97	97
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	52	52	52	52	52	52
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	2,068	2,068	2,068	2,068	2,068	2,068
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
2006 Subtotal						**3,491**	**3,491**	**3,491**	**3,491**	**3,491**	**2,217**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	472	472	472	472	472
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	487	487	487	487	487
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	1,584	1,560	1,560	1,560	1,560
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	4,420	4,420	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	101	101	101	101	101
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	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
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
2007 Subtotal						**0**	**7,063**	**7,039**	**2,619**	**2,619**	**2,619**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	651	651	651	651
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	343	343	343	343
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0	0	479	173	173	173
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	2,509	2,497	2,497	2,497
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0	0	796	796	796	796
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	3	3	3	3
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0	0	24	24	19	19
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	2	2	2	2
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
2008 Subtotal						**0**	**0**	**4,808**	**4,489**	**4,484**	**4,484**
Overall Total						**3,491**	**10,555**	**15,338**	**10,599**	**10,594**	**9,320**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	2012	2013	2014	2015	2016	2017	2018
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	97	97	97	97	97	97	97
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	2,068	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
2006 Subtotal						**2,165**	**97**	**97**	**97**	**97**	**97**	**97**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	470	470	470	381	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	431	431	431	431	431	431	431
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	1,402	1,402	1,402	152	152	27	27
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	101	101	101	101	101	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0	0
2007 Subtotal						**2,403**	**2,403**	**2,403**	**1,064**	**683**	**458**	**458**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	650	650	650	650	518	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	343	343	343	343	343	343	343
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	173	173	173	173	95	95	72
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	2,102	2,102	1,747	1,431	1,023	1,012	859
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	796	796	796	796	731	731	731
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	3	3	3	3	3	3	3
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	19	19	19	19	19	19	19
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	2	2	2	2	2	2	2
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0
2008 Subtotal						**4,088**	**4,088**	**3,733**	**3,417**	**2,734**	**2,205**	**2,029**
Overall Total						**8,656**	**6,588**	**6,234**	**4,578**	**3,514**	**2,760**	**2,584**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Gross Annual Energy Savings (MWh) 2020	2021	2022	2023	2024	2025	2026	2027
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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
2006 Subtotal						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	431	431	43	43	43	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	27	27	15	6	6	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	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
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	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
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	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
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
2007 Subtotal						**458**	**458**	**58**	**48**	**48**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	343	343	343	274	274	274	0	0
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	72	64	61	58	58	58	58	58
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	824	824	824	802	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	731	731	731	709	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	3	3	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	19	19	19	2	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	2	2	2	2	2	2	2	2
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0	0	0
2008 Subtotal						**1,994**	**1,986**	**1,980**	**1,847**	**334**	**334**	**60**	**60**
Overall Total						**2,452**	**2,444**	**2,038**	**1,895**	**382**	**334**	**60**	**60**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Gross Annual Energy Savings (MWh) 2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	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
2006 Subtotal						**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	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
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	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
2007 Subtotal						**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0
2008 Subtotal						**0**	**0**	**0**	**0**	**0**
Overall Total						**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Net Summer Peak Demand Savings (MW) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	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	10.67	10.67	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	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	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	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					**11**	**11**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	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	18.69	18.69	18.69	18.69	18.69	3.15	3.15	3.15	0.00	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	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	0.05	0.05	0.05	0.05	0.05	0.05	0.02	0.02	0.00	0.00	0.00	0.00
11	2007 peaksaver®	Consumer, Business	2007	Final	13.32	13.32	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	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	0.31	0.31	0.31	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	2007 Social Housing – Pilot	Consumer	2007	Final	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	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.00	0.00	0.00
16	2007 Toronto Comprehensive	Business	2007	Final	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	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	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	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	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	0.00	0.00
2007 Subtotal					**35**	**35**	**22**	**22**	**21**	**6**	**6**	**6**	**2**	**2**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	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	Final	14.82	14.82	14.82	14.82	14.82	14.82	12.02	12.02	12.02	0.00	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Final	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	Final	5.28	5.22	5.22	5.22	5.16	5.13	4.88	4.88	4.88	4.88	4.88	0.00
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2.30	2.03	2.03	0.99	0.99	0.99	0.99	0.00	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Final	34.05	34.05	34.05	34.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	9.86	9.86	9.86	9.86	9.86	9.86	9.57	0.00	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Final	4.88	4.87	4.87	4.79	4.79	4.79	4.69	0.45	0.45	0.45	0.45	0.00
29	2008 High Performance New Construction	Business	2008	Final	0.34	0.34	0.34	0.34	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	0.36	0.36	0.36	0.36	0.36	0.36	0.01	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	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	Final	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	Final	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	Final	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	Final	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	Final	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	0.00
2008 Subtotal					**81**	**81**	**81**	**80**	**45**	**45**	**41**	**26**	**26**	**14**	**14**	**0**
Overall Total					**126**	**126**	**102**	**101**	**67**	**51**	**47**	**32**	**29**	**16**	**14**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	0.89	0.89	0.89	0.89	0.89	0.00	0.00	0.00	0.00	0.00	0.00
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	10.67	10.67	10.67	10.67	10.67	10.67	10.67	10.67	10.67	10.67	10.67
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	1.27	1.27	1.27	1.27	1.27	1.27	0.00	0.00	0.00	0.00	0.00
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	3.34	3.34	3.34	3.34	3.34	3.34	3.34	0.00	0.00	0.00	0.00
6	2006 Demand Response 1	Industrial, Business	2006	Final	266.00	266.00	266.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal					**282**	**282**	**282**	**16**	**16**	**15**	**14**	**11**	**11**	**11**	**11**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0.00	1.54	1.54	1.54	1.54	1.54	1.36	1.36	1.36	1.04	0.00
8	2007 Cool Savings Rebate	Consumer	2007	Final	0.00	19.82	19.82	19.82	19.82	19.82	18.69	18.69	18.69	18.69	18.69
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0.00	0.96	0.96	0.96	0.96	0.00	0.00	0.00	0.00	0.00	0.00
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0.00	5.07	4.59	4.59	4.59	4.59	4.59	4.59	4.59	1.12	1.12
11	2007 peaksaver®	Consumer, Business	2007	Final	0.00	13.32	13.32	13.32	13.32	13.32	13.32	13.32	13.32	13.32	13.32
12	2007 Summer Savings	Consumer	2007	Final	0.00	45.00	45.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0.00	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
14	2007 Social Housing – Pilot	Consumer	2007	Final	0.00	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
16	2007 Toronto Comprehensive	Business	2007	Final	0.00	130.90	130.90	130.90	130.90	130.90	0.00	0.00	0.00	0.00	0.00
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0.00	1.80	1.80	1.80	1.80	1.80	0.00	0.00	0.00	0.00	0.00
18	2007 Demand Response 1	Industrial, Business	2007	Final	0.00	51.40	51.40	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	0.00	26.40	26.40	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	0.00	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
2007 Subtotal					**0**	**300**	**300**	**177**	**177**	**176**	**42**	**42**	**42**	**38**	**37**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0.00	0.00	3.67	3.67	3.67	3.67	3.56	3.56	3.56	3.56	2.75
22	2008 Cool Savings Rebate	Consumer	2008	Final	0.00	0.00	14.82	14.82	14.82	14.82	14.82	14.82	14.82	14.82	14.82
23	2008 Aboriginal	Consumer	2008	Final	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	Final	0.00	0.00	9.54	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.28
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0.00	0.00	6.48	6.19	6.19	6.19	5.62	5.62	4.33	3.89	2.85
26	2008 peaksaver®	Consumer, Business	2008	Final	0.00	0.00	34.05	34.05	34.05	34.05	34.05	34.05	34.05	34.05	34.05
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0.00	0.00	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	9.86
28	2008 Toronto Comprehensive	Business	2008	Final	0.00	0.00	10.30	10.30	10.27	10.27	10.27	10.27	10.27	10.27	8.32
29	2008 High Performance New Construction	Business	2008	Final	0.00	0.00	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
30	2008 Power Savings Blitz	Business	2008	Final	0.00	0.00	0.44	0.44	0.36	0.36	0.36	0.36	0.36	0.36	0.36
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	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	Final	0.00	0.00	122.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	0.00	0.00	85.00	85.00	85.00	85.00	85.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	0.00	0.00	2.80	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	Final	0.00	0.00	52.00	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	Final	0.00	0.00	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
2008 Subtotal					**0**	**0**	**361**	**179**	**179**	**179**	**179**	**94**	**92**	**92**	**88**
Overall Total					**282**	**583**	**943**	**373**	**373**	**371**	**235**	**146**	**145**	**141**	**136**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Net Summer Peak Demand Savings (MW)										
					2029	2030	2031	2032	2006	2007	2008	2009	2010	2011	2012
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	0.00	0.00	0.00	0.00	136,671.67	136,671.67	136,671.67	136,671.67	136,671.67	0.00	0.00
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	0.00	0.00	0.00	0.00	10,417.00	10,417.00	10,417.00	10,417.00	10,417.00	10,417.00	10,417.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	0.00	0.00	0.00	0.00	5,595.21	5,595.21	5,595.21	5,595.21	5,595.21	5,595.21	0.00
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	0.00	0.00	0.00	0.00	221,722.84	221,722.84	221,722.84	221,722.84	221,722.84	221,722.84	221,722.84
6	2006 Demand Response 1	Industrial, Business	2006	Final	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**	**374,407**	**374,407**	**374,407**	**374,407**	**374,407**	**237,735**	**232,140**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	13,539	13,539	13,539	13,539	13,539	13,460
8	2007 Cool Savings Rebate	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	30,191	30,191	30,191	30,191	30,191	29,153
9	2007 Aboriginal - Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	19,797	19,797	19,797	19,797	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	132,041	130,440	130,440	130,440	130,440	124,914
11	2007 peaksaver®	Consumer, Business	2007	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	81,000	81,000	0	0	0	0
13	2007 Affordable Housing - Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	4,254	4,254	4,254	4,254	4,254	4,254
14	2007 Social Housing - Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	11,900	11,900	11,900	11,900	11,900	11,900
15	2007 Energy Efficiency Assistance for Houses - Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00	0	2,300	2,300	2,300	2,300	2,300	2,300
16	2007 Toronto Comprehensive	Business	2007	Final	0.00	0.00	0.00	0.00	0	165,690	165,690	165,690	165,690	165,690	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0.00	0.00	0.00	0.00	0	5,000	5,000	5,000	5,000	5,000	5,000
18	2007 Demand Response 1	Industrial, Business	2007	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0.00	0.00	0.00	0.00	0	8,607	8,607	8,607	8,607	8,607	8,607
2007 Subtotal					**0**	**0**	**0**	**0**	**0**	**474,318**	**472,717**	**391,717**	**391,717**	**371,920**	**199,587**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0.00	0.00	0.00	0.00	0	0	34,024	34,024	34,024	34,024	33,911
22	2008 Cool Savings Rebate	Consumer	2008	Final	0.00	0.00	0.00	0.00	0	0	23,393	23,393	23,393	23,393	23,393
23	2008 Aboriginal	Consumer	2008	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	0.00	0.00	0.00	0.00	0	0	37,551	13,550	13,550	13,550	13,550
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0.00	0.00	0.00	0.00	0	0	118,754	118,237	118,237	118,237	100,356
26	2008 peaksaver®	Consumer, Business	2008	Final	0.00	0.00	0.00	0.00	0	0	681	681	681	681	681
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0.00	0.00	0.00	0.00	0	0	54,593	54,593	54,593	54,593	54,593
28	2008 Toronto Comprehensive	Business	2008	Final	0.00	0.00	0.00	0.00	0	0	58,059	58,032	57,546	57,546	57,546
29	2008 High Performance New Construction	Business	2008	Final	0.00	0.00	0.00	0.00	0	0	287	287	287	287	287
30	2008 Power Savings Blitz	Business	2008	Final	0.00	0.00	0.00	0.00	0	0	3,205	3,205	2,627	2,627	2,627
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	0.00	0.00	0	0	2,118	2,118	2,118	2,118	2,118
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	0.00	0.00	0	0	27,498	27,498	27,498	27,498	27,498
2008 Subtotal					**0**	**0**	**0**	**0**	**0**	**0**	**360,162**	**335,617**	**334,553**	**334,553**	**316,559**
Overall Total					**0**	**0**	**0**	**0**	**374,407**	**848,725**	**1,207,285**	**1,101,741**	**1,100,677**	**944,208**	**748,286**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Net Annual Energy Savings (MWh) 2025	2026	2027	2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	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	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	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	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	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**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	0	0	0	0	0	0	0	0
9	2007 Aboriginal - Pilot	Consumer	2007	Final	0	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0	0	0	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	0	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	0	0	0	0	0	0	0	0
13	2007 Affordable Housing - Pilot	Consumer	2007	Final	0	0	0	0	0	0	0	0
14	2007 Social Housing - Pilot	Consumer	2007	Final	0	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses - Pilot	Consumer	2007	Final	2,300	0	0	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	0	0	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	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
19	2007 Other Demand Response	Industrial, Business	2007	Final	0	0	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	8,607	8,607	0	0	0	0	0	0
2007 Subtotal					**10,907**	**8,607**	**0**	**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	18,655	0	0	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Final	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	4,512	4,512	4,512	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0	0	0	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Final	0	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0	0	0	0	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Final	6,885	6,885	6,885	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	0	0	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Final	0	0	0	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	2,118	2,118	2,118	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	27,498	27,498	27,498	0	0	0	0	0
2008 Subtotal					**59,667**	**41,012**	**41,012**	**0**	**0**	**0**	**0**	**0**
Overall Total					**70,574**	**49,619**	**41,012**	**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
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
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
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
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
6	2006 Demand Response 1	Industrial, Business	2006	Final	266.000	266.000	266.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2006 Subtotal					**284**	**284**	**284**	**18**	**18**	**17**	**16**	**12**	**12**	**12**	**12**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0.00	3.79	3.79	3.79	3.79	3.79	3.36	3.36	3.36	2.65	0.00
8	2007 Cool Savings Rebate	Consumer	2007	Final	0.00	39.73	39.73	39.73	39.73	39.73	32.53	32.53	32.53	32.53	32.53
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0.00	0.96	0.96	0.96	0.96	0.00	0.00	0.00	0.00	0.00	0.00
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0.00	7.34	6.48	6.48	6.48	6.48	6.48	6.48	6.48	2.00	2.00
11	2007 peaksaver®	Consumer, Business	2007	Final	0.00	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80
12	2007 Summer Savings	Consumer	2007	Final	0.00	375.00	375.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0.00	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
14	2007 Social Housing – Pilot	Consumer	2007	Final	0.00	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
16	2007 Toronto Comprehensive	Business	2007	Final	0.00	145.44	145.44	145.44	145.44	145.44	0.00	0.00	0.00	0.00	0.00
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0.00	2.00	2.00	2.00	2.00	2.00	0.00	0.00	0.00	0.00	0.00
18	2007 Demand Response 1	Industrial, Business	2007	Final	0.00	51.40	51.40	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	0.00	26.40	26.40	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	0.00	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
2007 Subtotal					**0**	**671**	**670**	**217**	**217**	**216**	**61**	**61**	**61**	**56**	**54**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0.00	0.00	6.87	6.87	6.87	6.87	6.55	6.55	6.55	6.55	5.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	0.00	0.00	25.73	25.73	25.73	25.73	25.73	25.73	25.73	25.73	25.73
23	2008 Aboriginal	Consumer	2008	Final	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	Final	0.00	0.00	12.23	7.01	7.01	7.01	7.01	7.01	7.01	7.01	6.77
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0.00	0.00	15.51	14.69	14.69	14.69	13.23	13.23	10.40	9.23	7.24
26	2008 peaksaver®	Consumer, Business	2008	Final	0.00	0.00	37.84	37.84	37.84	37.84	37.84	37.84	37.84	37.84	37.84
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0.00	0.00	17.37	17.37	17.37	17.37	17.37	17.37	17.37	17.37	17.11
28	2008 Toronto Comprehensive	Business	2008	Final	0.00	0.00	17.57	17.57	17.52	17.52	17.52	17.52	17.52	17.52	14.74
29	2008 High Performance New Construction	Business	2008	Final	0.00	0.00	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
30	2008 Power Savings Blitz	Business	2008	Final	0.00	0.00	0.48	0.48	0.39	0.39	0.39	0.39	0.39	0.39	0.39
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	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	Final	0.00	0.00	122.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	0.00	0.00	85.00	85.00	85.00	85.00	85.00	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	0.00	0.00	2.80	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	Final	0.00	0.00	52.00	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	Final	0.00	0.00	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
2008 Subtotal					**0**	**0**	**405**	**222**	**222**	**222**	**220**	**135**	**132**	**131**	**124**
Overall Total					**284**	**955**	**1,359**	**457**	**457**	**455**	**297**	**208**	**206**	**199**	**190**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Gross Summer Peak Demand Savings (MW) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	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	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	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	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	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					**12**	**12**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	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	32.53	32.53	32.53	32.53	32.53	5.51	5.51	5.51	0.00	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	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	0.07	0.07	0.07	0.07	0.07	0.07	0.02	0.02	0.00	0.00	0.00	0.00
11	2007 peaksaver®	Consumer, Business	2007	Final	14.80	14.80	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	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	0.31	0.31	0.31	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	2007 Social Housing – Pilot	Consumer	2007	Final	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	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.00	0.00	0.00
16	2007 Toronto Comprehensive	Business	2007	Final	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	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	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	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	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	0.00	0.00
2007 Subtotal					**50**	**50**	**35**	**35**	**35**	**8**	**8**	**8**	**2**	**2**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	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	Final	25.73	25.73	25.73	25.73	25.73	25.73	20.88	20.88	20.88	0.00	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Final	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	Final	6.77	6.70	6.70	6.70	6.61	6.58	6.25	6.25	6.25	6.25	6.25	0.00
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	5.99	5.31	5.31	2.95	2.95	2.95	2.95	0.00	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Final	37.84	37.84	37.84	37.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	17.11	17.11	17.11	17.11	17.11	17.11	16.60	0.00	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Final	7.98	7.95	7.95	7.83	7.83	7.83	7.67	0.74	0.74	0.74	0.74	0.00
29	2008 High Performance New Construction	Business	2008	Final	0.49	0.49	0.49	0.49	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	0.39	0.39	0.39	0.39	0.39	0.39	0.01	0.00	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	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	Final	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	Final	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	Final	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	Final	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	Final	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	0.00
2008 Subtotal					**111**	**111**	**111**	**108**	**70**	**70**	**63**	**37**	**37**	**16**	**16**	**0**
Overall Total					**173**	**173**	**146**	**143**	**105**	**78**	**71**	**45**	**39**	**18**	**16**	**0**

OPA Conservation & Demand Management Programs
Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Gross Summer Peak Demand Savings (MW) 2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	0.000	0.000	0.000	0.000
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	0.000	0.000	0.000	0.000
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	0.000	0.000	0.000	0.000
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	0.000	0.000	0.000	0.000
6	2006 Demand Response 1	Industrial, Business	2006	Final	0.000	0.000	0.000	0.000
2006 Subtotal					**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0.00	0.00	0.00	0.00
8	2007 Cool Savings Rebate	Consumer	2007	Final	0.00	0.00	0.00	0.00
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0.00	0.00	0.00	0.00
11	2007 peaksaver®	Consumer, Business	2007	Final	0.00	0.00	0.00	0.00
12	2007 Summer Savings	Consumer	2007	Final	0.00	0.00	0.00	0.00
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00
14	2007 Social Housing – Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0.00	0.00	0.00	0.00
16	2007 Toronto Comprehensive	Business	2007	Final	0.00	0.00	0.00	0.00
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0.00	0.00	0.00	0.00
18	2007 Demand Response 1	Industrial, Business	2007	Final	0.00	0.00	0.00	0.00
19	2007 Other Demand Response	Industrial, Business	2007	Final	0.00	0.00	0.00	0.00
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0.00	0.00	0.00	0.00
2007 Subtotal					**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0.00	0.00	0.00	0.00
22	2008 Cool Savings Rebate	Consumer	2008	Final	0.00	0.00	0.00	0.00
23	2008 Aboriginal	Consumer	2008	Final	0.00	0.00	0.00	0.00
24	2008 Summer Sweepstakes	Consumer	2008	Final	0.00	0.00	0.00	0.00
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0.00	0.00	0.00	0.00
26	2008 peaksaver®	Consumer, Business	2008	Final	0.00	0.00	0.00	0.00
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0.00	0.00	0.00	0.00
28	2008 Toronto Comprehensive	Business	2008	Final	0.00	0.00	0.00	0.00
29	2008 High Performance New Construction	Business	2008	Final	0.00	0.00	0.00	0.00
30	2008 Power Savings Blitz	Business	2008	Final	0.00	0.00	0.00	0.00
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	0.00	0.00	0.00	0.00
32	2008 Demand Response 1	Industrial, Business	2008	Final	0.00	0.00	0.00	0.00
33	2008 Demand Response 3	Industrial, Business	2008	Final	0.00	0.00	0.00	0.00
34	2008 Other Demand Response	Industrial, Business	2008	Final	0.00	0.00	0.00	0.00
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	0.00	0.00
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	0.00	0.00
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	0.00	0.00	0.00	0.00
2008 Subtotal					**0**	**0**	**0**	**0**
Overall Total					**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
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
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
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
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
6	2006 Demand Response 1	Industrial, Business	2006	Final	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**
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
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
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0	19,797	19,797	19,797	19,797	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
11	2007 peaksaver®	Consumer, Business	2007	Final	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
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
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
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
16	2007 Toronto Comprehensive	Business	2007	Final	0	184,100	184,100	184,100	184,100	184,100	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
18	2007 Demand Response 1	Industrial, Business	2007	Final	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
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
2007 Subtotal					**0**	**1,189,858**	**1,186,946**	**511,946**	**511,946**	**492,149**	**277,077**	**277,077**	**277,077**	**123,786**	**95,856**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0	0	62,711	62,711	62,711	62,711	62,398	62,398	62,398	62,398	48,800
22	2008 Cool Savings Rebate	Consumer	2008	Final	0	0	40,725	40,725	40,725	40,725	40,725	40,725	40,725	40,725	40,725
23	2008 Aboriginal	Consumer	2008	Final	0	0	0	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	0	0	48,142	17,372	17,372	17,372	17,372	17,372	17,372	17,372	9,517
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0	0	294,528	293,056	293,056	293,056	246,692	246,692	205,044	167,916	120,070
26	2008 peaksaver®	Consumer, Business	2008	Final	0	0	757	757	757	757	757	757	757	757	757
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0	0	97,310	97,309	97,309	97,309	97,309	97,309	97,309	97,309	89,372
28	2008 Toronto Comprehensive	Business	2008	Final	0	0	99,960	99,917	99,137	99,137	99,137	98,878	98,878	98,878	92,425
29	2008 High Performance New Construction	Business	2008	Final	0	0	410	410	410	410	410	410	410	410	410
30	2008 Power Savings Blitz	Business	2008	Final	0	0	3,447	3,447	2,825	2,825	2,825	2,825	2,825	2,802	2,802
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	0	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498
2008 Subtotal					**0**	**0**	**677,605**	**645,319**	**643,918**	**643,918**	**597,241**	**596,982**	**555,334**	**518,183**	**434,492**
Overall Total					**416,007**	**1,605,865**	**2,280,559**	**1,573,273**	**1,571,872**	**1,400,217**	**1,132,252**	**885,634**	**843,986**	**653,544**	**541,923**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Gross Annual Energy Savings (MWh) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	0	0	0	0	0	0	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	11,574	11,574	0	0	0	0	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	0	0	0	0	0	0	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	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
2006 Subtotal					**11,574**	**11,574**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0	0	0	0	0	0	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	50,864	50,864	50,864	50,864	50,864	5,050	5,050	5,050	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0	0	0	0	0	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	3,206	3,206	3,206	3,206	3,206	1,807	673	673	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	0	0	0	0	0	0	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	4,254	4,254	4,254	4,254	0	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	0	0	0	0	0	0	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	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
19	2007 Other Demand Response	Industrial, Business	2007	Final	0	0	0	0	0	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	0
2007 Subtotal					**69,231**	**69,231**	**69,231**	**69,231**	**64,977**	**17,763**	**16,629**	**16,629**	**10,907**	**8,607**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0	0	0	0	0	0	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	40,725	40,725	40,725	40,725	40,725	40,725	32,497	32,497	32,497	0	0
23	2008 Aboriginal	Consumer	2008	Final	0	0	0	0	0	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	9,517	7,211	7,211	7,211	6,380	6,084	5,784	5,784	5,784	5,784	5,784
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	118,827	100,820	100,820	96,741	96,741	96,741	94,100	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Final	757	757	757	757	0	0	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	89,372	89,372	89,372	89,372	89,372	89,372	86,690	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Final	67,575	67,535	67,535	66,407	66,407	66,407	65,230	11,748	11,748	11,748	11,748
29	2008 High Performance New Construction	Business	2008	Final	410	410	410	410	410	0	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Final	2,802	2,802	2,802	2,802	2,802	2,802	68	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	0	0	0	0	0	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	0	0	0	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498
2008 Subtotal					**359,600**	**339,246**	**339,246**	**334,040**	**332,452**	**331,746**	**313,985**	**79,645**	**79,645**	**47,148**	**47,148**
Overall Total					**440,405**	**420,052**	**408,477**	**403,271**	**397,429**	**349,509**	**330,614**	**96,274**	**90,551**	**55,754**	**47,148**

OPA Conservation & Demand Management Programs

Initiative Results

For: Whitby Hydro Electric Corporation

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Gross Annual Energy Savings (MWh) 2028	2029	2030	2031	2032
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	0	0	0	0	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	0	0	0	0	0
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	0	0	0	0	0
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	0	0	0	0	0
6	2006 Demand Response 1	Industrial, Business	2006	Final	0	0	0	0	0
2006 Subtotal					**0**	**0**	**0**	**0**	**0**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0	0	0	0	0
8	2007 Cool Savings Rebate	Consumer	2007	Final	0	0	0	0	0
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0	0	0	0	0
11	2007 peaksaver®	Consumer, Business	2007	Final	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	0	0	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	0	0	0	0	0
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0	0	0	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0	0	0	0	0
18	2007 Demand Response 1	Industrial, Business	2007	Final	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0	0	0	0	0
2007 Subtotal					**0**	**0**	**0**	**0**	**0**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0	0	0	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	0	0	0	0	0
23	2008 Aboriginal	Consumer	2008	Final	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	0	0	0	0	0
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0	0	0	0	0
26	2008 peaksaver®	Consumer, Business	2008	Final	0	0	0	0	0
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0	0	0	0	0
28	2008 Toronto Comprehensive	Business	2008	Final	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	0	0	0	0	0
30	2008 Power Savings Blitz	Business	2008	Final	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	0	0	0
2008 Subtotal					**0**	**0**	**0**	**0**	**0**
Overall Total					**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs

Measure Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	#	Measure Name	Unit Savings Assumptions: Summer Peak Demand Savings per Unit (kW)	Unit Savings Assumptions: Annual Energy Savings per Unit (kWh)	Unit Savings Assumptions: Effective Useful Life (EUL)	Net-to-Gross Adjustments (%): Free Rider (#1)	Net-to-Gross Adjustments (%): Spill Over (#2)	Net-to-Gross Adjustments (%): Exclusions (#3)	Net-to-Gross Adjustments (%): Part Use (#4)	Net-to-Gross Adjustments (%): Other (#5)	Net-to-Gross Adjustments (%): Aggregate (#6)	Provincial Total (# Units)	LDC Total (# Units)
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	11,231
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2	Electric Timers	0.00	183	20	90%	100%	100%	100%	100%	90%	37,518	315
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	3	Programmable Thermostats	0.05	216	15	90%	100%	100%	100%	100%	90%	16,320	137
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	104
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	121
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2	Programmable Thermostats	0.16	159	18	90%	100%	100%	100%	100%	90%	10,965	92
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	82
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	42
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2	Freezer Retirement	0.20	900	6	90%	100%	100%	100%	100%	90%	217	2
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	16,653
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	4,008
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	3	Programmable Thermostats	0.12	522	18	90%	100%	100%	100%	100%	90%	31,484	264
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	4	Dimmers	0.00	139	10	90%	100%	100%	100%	100%	90%	0	209
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	5	Indoor Motion Sensors	0.00	209	20	90%	100%	100%	100%	100%	90%	0	75
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	16
6	2006 Demand Response 1	Industrial, Business	2006	Final	1	Voluntary Load Shedding Project	Custom	Custom	3	100%	100%	100%	100%	100%	100%	n/a	n/a

OPA Conservation & Demand Management Programs

Measure Results

For: Whitby Hydro Electric Corporation

#	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)		
2007																	
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	1	Refrigerator	0.07	745	9	48%	100%	100%	81%	100%	39%	37,123	506
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	2	Freezer	0.07	515	8	50%	100%	100%	91%	100%	46%	10,652	170
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	3	Small Refrigerator	0.05	490	9	38%	100%	100%	79%	100%	30%	581	8
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	4	Small Freezer	0.04	339	8	38%	100%	100%	79%	100%	30%	325	5
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	5	Window Air Conditioner	0.56	240	5	43%	100%	100%	100%	100%	43%	758	8
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	281
8	2007 Cool Savings Rebate	Consumer	2007	Final	2	Programmable Thermostat	0.03	55	15	46%	0%	60%	100%	100%	27%	46,989	398
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	440
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	237
9	2007 Aboriginal – Pilot	Consumer	2007	Final	1	Consumer Retrofit Kit	0.04	900	4	100%	100%	100%	100%	100%	100%	21,997	0
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	20,115
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2	20 W+ CFLs	0.00	62	8	78%	100%	100%	100%	100%	78%	386,799	3,274
10	2007 Every Kilowatt Counts	Consumer	2007	Final	3	Project Porchlight CFLs	0.00	43	8	76%	100%	100%	100%	100%	76%	500,000	4,233
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	162
10	2007 Every Kilowatt Counts	Consumer	2007	Final	5	Furnace Filter	0.01	38	1	55%	100%	100%	100%	100%	55%	77,226	654
10	2007 Every Kilowatt Counts	Consumer	2007	Final	6	Solar Lights	0.00	33	5	13%	100%	100%	100%	100%	13%	305,048	2,582
10	2007 Every Kilowatt Counts	Consumer	2007	Final	7	Outdoor Motion Sensor	0.00	160	10	55%	100%	100%	100%	100%	55%	30,516	258
10	2007 Every Kilowatt Counts	Consumer	2007	Final	8	Dimmer Switch	0.00	24	10	55%	100%	100%	100%	100%	55%	19,390	164
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	78
10	2007 Every Kilowatt Counts	Consumer	2007	Final	10	SLEDs	0.00	14	5	49%	100%	100%	100%	100%	49%	629,498	5,329
10	2007 Every Kilowatt Counts	Consumer	2007	Final	11	T8	0.00	37	18	77%	100%	100%	100%	100%	77%	18,088	153
10	2007 Every Kilowatt Counts	Consumer	2007	Final	12	Programmable Thermostat	0.00	75	15	55%	100%	100%	100%	100%	55%	18,633	158
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	71
10	2007 Every Kilowatt Counts	Consumer	2007	Final	14	Lighting Control Devices	0.02	72	10	55%	100%	100%	100%	100%	55%	97,742	827
11	2007 peaksaver®	Consumer, Business	2007	Final	1	Residential Programmable Thermostat	0.63	0	12	90%	100%	100%	100%	100%	90%	12,360	0
11	2007 peaksaver®	Consumer, Business	2007	Final	2	Residential Air Conditioner Switch	0.63	0	12	90%	100%	100%	100%	100%	90%	3,733	0
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	5,618
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
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

OPA Conservation & Demand Management Programs

Measure Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	#	Measure Name	Unit Savings Assumptions: Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)	Effective Useful Life (EUL)	Net-to-Gross Adjustments (%): Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)	Provincial Total (# Units)	LDC Total (# Units)
2007																	
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	82
15	2007 Energy Efficiency Assistance for Hou	Consumer	2007	Final	1	Custom Retrofit Projects	Custom	Custom	19	100%	100%	100%	100%	100%	100%	544	0
16	2007 Toronto Comprehensive	Business	2007	Final	1	City of Toronto - Better Building Partnership Project	Custom	Custom	5	90%	100%	100%	100%	100%	90%	0	0
16	2007 Toronto Comprehensive	Business	2007	Final	2	Toronto Hydro - Business Incentive Program Project	Custom	Custom	5	90%	100%	100%	100%	100%	90%	24	0
16	2007 Toronto Comprehensive	Business	2007	Final	3	Building Owners & Managers Association - Toronto Pr	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%	n/a	n/a
19	2007 Other Demand Response	Industrial, Business	2007	Final	1	Loblaw Contract	Custom	Custom	2	100%	100%	100%	100%	100%	100%	n/a	n/a
19	2007 Other Demand Response	Industrial, Business	2007	Final	2	Rodan Contract	Custom	Custom	2	100%	100%	100%	100%	100%	100%	n/a	n/a
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Incom	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-Incom	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-Incom	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-Incom	2007	Final	4	Bio-Energy	Custom	Custom	20	100%	100%	100%	100%	100%	100%	2	0

OPA Conservation & Demand Management Programs

Measure Results

For: Whitby Hydro Electric Corporation

#	Initiative Name	Program Name	Program Year	Results Status	#	Measure Name	Unit Savings Assumptions: Summer Peak Demand Savings per Unit (kW)	Unit Savings Assumptions: Annual Energy Savings per Unit (kWh)	Unit Savings Assumptions: Effective Useful Life (EUL)	Net-to-Gross Adjustments (%): Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)	Provincial Total (# Units)	LDC Total (# Units)
2008																	
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	1	Refrigerator	0.08	775	9	55%	100%	100%	100%	100%	55%	62,968	669
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	2	Freezer	0.08	740	8	52%	100%	100%	100%	100%	52%	18,376	178
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	3	Room Air Conditioner	0.20	197	4.5	36%	100%	100%	100%	100%	36%	1,587	5
22	2008 Cool Savings Rebate	Consumer	2008	Final	1	2007 Efficient Furnance with Electronically Commutab	0.50	837	15	54%	100%	100%	100%	5%	100%	9,366	79
22	2008 Cool Savings Rebate	Consumer	2008	Final	2	2007 ENERGYSTAR® Central Air Conditioner	0.17	155	18	52%	100%	100%	100%	5%	100%	4,499	38
22	2008 Cool Savings Rebate	Consumer	2008	Final	3	2007 Programable Thermostat	0.03	54	15	46%	100%	100%	100%	0%	60%	7,291	61
22	2008 Cool Savings Rebate	Consumer	2008	Final	4	2007 Central Air Conditioner Tune-ups	0.26	235	5	16%	100%	100%	100%	0%	100%	0	0
22	2008 Cool Savings Rebate	Consumer	2008	Final	5	2008 Efficient Furnance with Electronically Commutab	0.49	819	18	54%	100%	100%	100%	5%	100%	33,546	282
22	2008 Cool Savings Rebate	Consumer	2008	Final	6	2008 ENERGYSTAR® Central Air Conditioner	0.14	125	18	52%	100%	100%	100%	5%	100%	22,241	187
22	2008 Cool Savings Rebate	Consumer	2008	Final	7	2008 Programable Thermostat	0.03	54	18	46%	100%	100%	100%	0%	60%	28,505	240
23	2008 Aboriginal	Consumer	2008	Final	1	Building Retrofits	1.60	2,820	10	100%	100%	100%	100%	100%	100%	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	1	Households	0.20	768	1	78%	100%	100%	100%	100%	78%	62,670	624
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	1	Air Conditioner/Furnace Filters	0.02	38	1	35%	100%	100%	100%	100%	100%	39,053	333
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	2	Energy Star® Qualified Compact Fluorescent Floods (	0.00	88	7	37%	100%	100%	100%	100%	100%	423,741	3,610
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	3	Energy Star® Qualified Light Fixtures	0.00	133	16	33%	100%	100%	100%	100%	100%	657,609	5,602
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	4	Heavy Duty Timers	0.02	301	10	33%	100%	100%	100%	100%	100%	14,885	127
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	5	T8 Fluorescent Fixtures	0.00	37	16	33%	100%	100%	100%	100%	100%	119,646	1,019
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	6	ENERGY STAR Decorative CFLs	0.00	30	4	39%	100%	100%	100%	100%	100%	1,526,248	13,003
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	7	ENERGY STAR Dimmable CFLs	0.00	98	6	38%	100%	100%	100%	100%	100%	98,397	838
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	8	Power Bars with Timers	0.00	53	10	41%	100%	100%	100%	100%	100%	7,055	60
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	9	Programmable Thermostats - Baseboard	0.00	64	15	47%	100%	100%	100%	100%	100%	41,495	354
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	10	Car block heater timer	n/a	n/a	n/a	0%	100%	100%	100%	100%	100%	n/a	n/a
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	11	Energy Star® Qualified Compact Fluorescent Light Bu	0.00	53	8	52%	100%	100%	100%	100%	100%	903,439	7,697
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	12	Lighting Control Devices	0.00	102	10	45%	100%	100%	100%	100%	100%	128,609	1,096
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	13	Awnings	0.00	0	n/a	0%	100%	100%	100%	100%	100%	28,376	242
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	14	Window Films	0.00	0	n/a	0%	100%	100%	100%	100%	100%	457,649	3,899
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	15	Electric Water Heater Blankets	0.00	0	n/a	0%	100%	100%	100%	100%	100%	14,029	120
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	16	Pipe Wrap	0.00	38	6	47%	100%	100%	100%	100%	100%	842,772	7,180
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	17	Low-Flow Toilets	0.00	0	n/a	0%	100%	100%	100%	100%	100%	110,248	939
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	18	Keep Cool – Dehumidifier	0.29	500	12	35%	100%	100%	100%	100%	100%	263	2
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	19	Keep Cool – Room Air Conditioner	0.14	141	9	42%	100%	100%	100%	100%	100%	295	3
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	20	Rewards for Recycling – Dehumidifier	0.29	500	12	44%	100%	100%	100%	100%	100%	7,897	67
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	21	Rewards for Recycling – Room Air Conditioner	0.14	141	9	44%	100%	100%	100%	100%	100%	8,535	73
25	2008 Every Kilowatt Counts Power Savings	Consumer	2008	Final	22	Rewards for Recycling - Halogen Lamp	0.01	275	16	48%	100%	100%	100%	100%	100%	6,808	58
26	2008 peaksaver®	Consumer, Business	2008	Final	1	Residential Programmable Thermostat	0.87	17	13	90%	100%	100%	100%	100%	90%	28,831	0
26	2008 peaksaver®	Consumer, Business	2008	Final	2	Residential Air Conditioner Switch	0.87	17	13	90%	100%	100%	100%	100%	90%	14,152	0
26	2008 peaksaver®	Consumer, Business	2008	Final	3	Residential Water Heater Switch	0.30	6	13	90%	100%	100%	100%	100%	90%	318	0
26	2008 peaksaver®	Consumer, Business	2008	Final	4	Commercial Programmable Thermostat	3.70	74	13	90%	100%	100%	100%	100%	90%	104	0
26	2008 peaksaver®	Consumer, Business	2008	Final	5	Commercial Air Conditioner Switch	3.70	74	13	90%	100%	100%	100%	100%	90%	47	0
26	2008 peaksaver®	Consumer, Business	2008	Final	6	Commercial Water Heater Switch	1.85	37	13	90%	100%	100%	100%	100%	90%	1	0

OPA Conservation & Demand Management Programs

Measure Results

For: Whitby Hydro Electric Corporation

#	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)		
2008																	
27	2008 Electricity Retrofit Incentive	Business	2008	Final	1	Agribusiness ENERGY STAR® Rated Exit Signs, All	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	2	Agribusiness ENERGY STAR® Rated CFLs, Screw in	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	3	Agribusiness ENERGY STAR® Rated CFLs, Hard wir	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	4	Agribusiness Standard Performance T8, Single lamp s	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	5	Agribusiness Standard Performance T8, Double lamp	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	6	Agribusiness Standard Performance T8, Triple lamp st	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	7	Agribusiness Standard Performance T8, Quadruple lar	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	8	Agribusiness High Performance T8 (Consortium for En	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	9	Agribusiness High Performance T8 (Consortium for En	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	10	Agribusiness High Performance T8 (Consortium for En	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	11	Agribusiness High Performance T8 (Consortium for En	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	12	Agribusiness T5 Fixtures, T5 fixture with 1, 2, or 3 lam	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	13	Agribusiness T5 Fixtures, High Bay T5. Maximum 6 l	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	14	Agribusiness Metal Halide, 320 W Ceramic pulse star	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	15	Agribusiness Occupancy Sensors, Switch plate moun	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	16	Agribusiness Occupancy Sensors, Ceiling mounted o	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	17	Agribusiness Creep Heat Pads, up to 100W maximum	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	18	Agribusiness Creep Heat Pads, up to 200W maximum	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	19	Agribusiness High Temperature Cutout Thermostat	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	20	Agribusiness Creep Heat Controller	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	21	Agribusiness Energy Efficient Ventilation Exhaust Far	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	22	Agribusiness Low Energy Livestock Waterers	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	23	Agribusiness Photocell and Timer for Lighting Control	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	24	Lighting System Exit Signs, 5 W or less	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	25	Lighting System ENERGY STAR® Rated CFLs, Scre	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	26	Lighting System ENERGY STAR® Rated CFLs, Hard	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	27	Lighting System Standard Performance T8, Single lam	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	28	Lighting System Standard Performance T8, Double lar	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	29	Lighting System Standard Performance T8, Triple lam	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	30	Lighting System Standard Performance T8, Quadruple	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	31	Lighting System High Performance T8 (Consortium for	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	32	Lighting System High Performance T8 (Consortium for	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	33	Lighting System High Performance T8 (Consortium for	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	34	Lighting System High Performance T8 (Consortium for	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	35	Lighting System T5 Fixtures, T5 fixture with 1, 2, or 3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	36	Lighting System T5 Fixtures, High Bay T5. Maximum	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	37	Lighting System Metal Halide, 320 W Ceramic pulse s	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	38	Lighting System Occupancy Sensors, Switch plate m	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	39	Lighting System Occupancy Sensors, Ceiling mounte	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	40	Motor Open Drip-Proof (ODP), 1 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	41	Motor Open Drip-Proof (ODP), 1.5 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

OPA Conservation & Demand Management Programs
Measure Results

For: Whitby Hydro Electric Corporation

#	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)		
2008																	
27	2008 Electricity Retrofit Incentive	Business	2008	Final	42	Motor Open Drip-Proof (ODP), 2 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	43	Motor Open Drip-Proof (ODP), 3 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	44	Motor Open Drip-Proof (ODP), 5 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	45	Motor Open Drip-Proof (ODP), 7.5 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	46	Motor Open Drip-Proof (ODP), 10 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	47	Motor Open Drip-Proof (ODP), 15 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	48	Motor Open Drip-Proof (ODP), 20 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	49	Motor Open Drip-Proof (ODP), 25 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	50	Motor Open Drip-Proof (ODP), 30 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	51	Motor Open Drip-Proof (ODP), 40 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	52	Motor Open Drip-Proof (ODP), 50 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	53	Motor Open Drip-Proof (ODP), 60 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	54	Motor Open Drip-Proof (ODP), 75 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	55	Motor Open Drip-Proof (ODP), 100 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	56	Motor Open Drip-Proof (ODP), 125 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	57	Motor Open Drip-Proof (ODP), 150 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	58	Motor Open Drip-Proof (ODP), 200 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	59	Motor Totally Enclosed Fan-Cooled (TEFC), 1 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	60	Motor Totally Enclosed Fan-Cooled (TEFC), 1.5 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	61	Motor Totally Enclosed Fan-Cooled (TEFC), 2 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	62	Motor Totally Enclosed Fan-Cooled (TEFC), 3 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	63	Motor Totally Enclosed Fan-Cooled (TEFC), 5 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	64	Motor Totally Enclosed Fan-Cooled (TEFC), 7.5 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	65	Motor Totally Enclosed Fan-Cooled (TEFC), 10 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	66	Motor Totally Enclosed Fan-Cooled (TEFC), 15 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	67	Motor Totally Enclosed Fan-Cooled (TEFC), 20 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	68	Motor Totally Enclosed Fan-Cooled (TEFC), 25 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	69	Motor Totally Enclosed Fan-Cooled (TEFC), 30 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	70	Motor Totally Enclosed Fan-Cooled (TEFC), 40 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	71	Motor Totally Enclosed Fan-Cooled (TEFC), 50 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	72	Motor Totally Enclosed Fan-Cooled (TEFC), 60 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	73	Motor Totally Enclosed Fan-Cooled (TEFC), 75 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	74	Motor Totally Enclosed Fan-Cooled (TEFC), 100 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	75	Motor Totally Enclosed Fan-Cooled (TEFC), 125 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	76	Motor Totally Enclosed Fan-Cooled (TEFC), 150 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	77	Motor Totally Enclosed Fan-Cooled (TEFC), 200 HP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	78	Transformer Size 15	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	79	Transformer Size 30	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	80	Transformer Size 45	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	81	Transformer Size 75	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	82	Transformer Size 112.5	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	83	Transformer Size 150	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	84	Transformer Size 225	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	85	Transformer Size 300	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

OPA Conservation & Demand Management Programs

Measure Results

For: Whitby Hydro Electric Corporation

#	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)		
2008																	
27	2008 Electricity Retrofit Incentive	Business	2008	Final	86	Transformer Size 500	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	87	Transformer Size 750	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	88	Transformer Size 1000	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	89	Unitary AC Single Phase <= 5.4 Tons	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	90	Unitary AC 3 Phase <= 5.4 Tons	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	91	Unitary AC >5.4 & <= 11.25 tons	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	92	Unitary AC >11.25 & <= 20 tons	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	93	Unitary AC 25 tons	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	2008 Electricity Retrofit Incentive	Business	2008	Final	94	Custom	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
28	2008 Toronto Comprehensive	Business	2008	Final	1	City of Toronto - Better Building Partnership Project	Custom	Custom	Custom	Custom	100%	100%	100%	100%	Custom	n/a	n/a
28	2008 Toronto Comprehensive	Business	2008	Final	2	Toronto Hydro - Business Incentive Program Project	Custom	Custom	Custom	Custom	100%	100%	100%	100%	Custom	n/a	n/a
28	2008 Toronto Comprehensive	Business	2008	Final	3	Building Owners & Managers Association - Toronto P	Custom	Custom	Custom	Custom	100%	100%	100%	100%	Custom	n/a	n/a
29	2008 High Performance New Construction	Business	2008	Final	1	Custom New Construction Project	Custom	Custom	14	Custom	100%	100%	100%	100%	Custom	n/a	n/a
30	2008 Power Savings Blitz	Business	2008	Final	1	T8 Fixture With Electronic Balllast	0.02	151	15	93%	100%	100%	100%	100%	93%	18,026	112
30	2008 Power Savings Blitz	Business	2008	Final	2	Energy Star® rated LED Exit Sign	0.03	237	16	93%	100%	100%	100%	100%	93%	287	10
30	2008 Power Savings Blitz	Business	2008	Final	3	Energy Star® rated CLF	0.03	191	2	93%	100%	100%	100%	100%	93%	3,256	27
30	2008 Power Savings Blitz	Business	2008	Final	4	Electric Water Heater Tank Wrap	0.05	436	7	93%	100%	100%	100%	100%	93%	53	0
30	2008 Power Savings Blitz	Business	2008	Final	5	Electric Water Heater Pipe Insulation	0.03	277	15	93%	100%	100%	100%	100%	93%	35	0
30	2008 Power Savings Blitz	Business	2008	Final	6	Aerator	0.03	310	5	93%	100%	100%	100%	100%	93%	1	0
30	2008 Power Savings Blitz	Business	2008	Final	7	Halogen	1.96	14	1	93%	100%	100%	100%	100%	93%	0	0
30	2008 Power Savings Blitz	Business	2008	Final	8	Other	0.00	0	0	100%	100%	100%	100%	100%	100%	1,775	10
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	1	Mixed Use Facility	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	2	University Campus	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	3	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	3	Hospital	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	4	Commercial Office Tower	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	5	Industrial/Manufacturing Facility	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	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	Final	7	Hotel	TBD	TBD	TBD	70%	100%	100%	100%	100%	70%	1	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	1	Voluntary Load Shedding Project	Custom	Custom	1	100%	100%	100%	100%	100%	100%	n/a	n/a
33	2008 Demand Response 3	Industrial, Business	2008	Final	1	Contractual Load Shedding Project	Custom	Custom	5	100%	100%	100%	100%	100%	100%	n/a	n/a
34	2008 Other Demand Response	Industrial, Business	2008	Final	1	Loblaw Contract	Custom	Custom	1	100%	100%	100%	100%	100%	100%	n/a	n/a
34	2008 Other Demand Response	Industrial, Business	2008	Final	2	Rodan Contract	Custom	Custom	1	100%	100%	100%	100%	100%	100%	n/a	n/a
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Incom	2008	Final	1	Hydro One Networks - Double Return	52,000.00	0	1	100%	100%	100%	100%	100%	100%	n/a	n/a
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Incom	2008	Final	1	Hydro	Custom	Custom	20	100%	100%	100%	100%	100%	100%	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Incom	2008	Final	2	Wind	Custom	Custom	20	100%	100%	100%	100%	100%	100%	7	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Incom	2008	Final	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-Incom	2008	Final	4	Bio-Energy	Custom	Custom	20	100%	100%	100%	100%	100%	100%	2	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Incom	2008	Final	1	Combined Heat & Power / By-Product	Custom	Custom	20	100%	100%	100%	100%	100%	100%	2	0