ORANGEVILLE HYDRO

August 27, 2009

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

Re: Orangeville Hydro Limited
2010 Rate Application EB-2009-0272

Dear Ms. Walli:

Orangeville Hydro Limited (OHL) is submitting its' 2010 Cost of Service Rate Application, in compliance with the OEB Filing Requirements for Transmission and Distribution Applications. The components for the application are as follows:

- ✓ Exhibit 1 – Administration
- ✓ Exhibit 2 – Rate Base
- ✓ Exhibit 3 – Operating Revenue
- ✓ Exhibit 5 – Cost of Capital and Capital Structure
- ✓ Exhibit 6 – Calculation of Revenue Deficiency or Surplus
- ✓ Exhibit 7 – Cost Allocation
- ✓ Exhibit 8 – Rate Design
- ✓ Exhibit 9 – Deferral and Variance Accounts
- ✓ Addendum – OHL Green Energy Plan

OHL is also pleased to submit in an Addendum to our cost of service filing, a copy of our Green Energy plan for approval.

Further to the Board's RESS filing guidelines, an electronic copy of our full application will be submitted through the OEB e-Filing Services. Two hard copies of the application are being sent by courier. If you have any questions, please do not hesitate to contact me at 519-942-8000 or jhoward@orangevillehydro.on.ca.

Orangeville Hydro Limited

Jan Howard
Manager of Finance & Rates

400 C Line, Orangeville ON L9W 2Z7 519-942-8000

ORANGEVILLE HYDRO LIMITED

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2010

INDEX

Exhibit	**Tab**	**Schedule**	**Appendix**	**Contents**
				Statements and Revenue Deficiency Statements
1-Administrative Documents-Cont.		4		Information on Affiliates
		5	I	Copy of Orangeville Hydro 2008 Annual Report
		6	J	Management Discussion and Analysis
		7	K	Revenue Requirement Work Form

Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency or Surplus				
	1	1		Revenue Deficiency - Overview

Orangeville Hydro Limited
EB-2009-0272
Exhibit 1
Tab 1
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ADDENDUM
Page 1 of 1
Filed: August 28, 2009

ADDENDUM

GREEN ENERGY PLAN

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 Orangeville Hydro Limited 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 Orangeville Hydro Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2010.
Applicant's Name:	Orangeville Hydro Limited
Applicant's Address for Service:	PO Box 400 400 C Line Orangeville, Ontario L9W 2Z7
	Attention: Mr. George Dick, President
	Telephone: 519-942-8000 Fax: 519-941-6061 E-mail: gdick@orangevillehydro.on.ca

APPLICATION

1. Introduction

(a) The Applicant is Orangeville Hydro Limited (referred to in this Application as the "Applicant" or "OHL"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the Town of Orangeville. The Applicant carries on the business of distributing electricity within the Town of Orangeville and the former Village of Grand Valley.

(b) The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (the "OEB Act")* for approval of its proposed distribution rates and other charges, effective May 1, 2010. A list of requested approvals is set out in Exhibit 1, Tab 1, and Schedule 5.

(c) Except where specifically identified in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated November 14, 2006 (the "Filing Requirements") in order to prepare this application.

2. Proposed Distribution Rates and Other Charges

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

3. Proposed Effective Date of Rate Order

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

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

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

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

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

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

(iv) the other service charges with exception of the temporary service charges proposed by the Applicant are the same as those previously approved by the OEB; and

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

5. Relief Sought

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

6. Form of Hearing Requested

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

DATED at Toronto, Ontario, this 15th day of August, 2009.

All of which is respectfully submitted,
ORANGEVILLE HYDRO LIMITED

George Dick
President

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

Residential

Service Charge	**$**	17.46
Smart Meter Rate Adder		1.00
Distribution Volumetric Rate	**$/kWh**	0.0134
LV Charges	**$/kWh**	0.0009
Rate Rider	**$/kWh**	(0.0013)
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030
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	**$**	33.52
Smart Meter Rate Adder		1.00
Distribution Volumetric Rate	**$/kWh**	0.0103
LV Charges	**$/kWh**	0.0008
Rate Rider	**$/kWh**	(0.0013)
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0027
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	**$**	264.94
Smart Meter Rate Adder		1.00
Distribution Volumetric Rate	**$/kW**	1.8345
LV Charges	**$/kW**	0.3149
Rate Rider	**$/kW**	(0.5080)
Retail Transmission Rate – Network Service Rate	**$/kW**	1.9365
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.0761
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)	**$**	6.40
Distribution Volumetric Rate	**$/kWh**	0.0091
LV Charges	**$/kWh**	0.0008
Rate Rider	**$/kWh**	(0.0010)
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0027
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0013
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25

Sentinel Lighting

Service Charge (per connection)	**$**	1.91
Distribution Volumetric Rate	**$/kW**	7.4165
LV Charges	**$/kW**	0.2485
Rate Rider	**$/kW**	(0.4868)
Retail Transmission Rate – Network Service Rate	**$/kW**	1.4678
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8493
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0013
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25

Street Lighting

Service Charge (per connection)	**$**	0.81
Distribution Volumetric Rate	**$/kW**	4.4557
LV Charges	**$/kW**	0.2485
Rate Rider	**$/kW**	(0.4520)
Retail Transmission Rate – Network Service Rate	**$/kW**	1.4605
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8318
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
Request for other billing information	**$**	15.00
Income tax letter	**$**	15.00
Returned cheque charge (plus bank charges)	**$**	15.00
Legal letter charge	**$**	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	**$**	30.00
Special meter reads	**$**	30.00

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

Temporary service install & remove - overhead - no transformer	**$**	500.00
Install/Remove load control device - during regular hours	**$**	65.00
Install/Remove load control device - after regular hours	**$**	185.00
Specific Charge for Access to the Power Poles $/pole/year	**$**	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)
	$/kW	0.00
	$/kW	0.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0468
Total Loss Factor – Secondary Metered Customer > 5,000 kW	0.0000
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0363
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0134

DISTRIBUTOR LICENCE:

Per the Draft Filing Requirements, the Orangeville Hydro Limited Distribution License ED-2000-0500 is no longer required.

CONTACT INFORMATION:

ORANGEVILLE HYDRO LIMITED
P.O. Box 400
400 C LINE
ORANGEVILLE, ON
L9W 2Z7

PRESIDENT:

Mr. George Dick
Telephone: 519-942-8000
Facsimile: 519-941-6061
E-mail: gdick@orangevillehydro.on.ca

MANAGER OF FINANCE & RATES:

Mrs. Jan Howard
Telephone: 519-942-8000
Facsimile: 519-941-6061
E-mail: jhoward@orangevillehydro.on.ca

SPECIFIC APPROVALS REQUESTED:

In this proceeding, OHL is requesting the following approvals:

- Approval to charge rates effective May 1, 2010 to recover a revenue requirement of $5,362,234 which includes a revenue deficiency of $631,388

- as set out in Exhibit 1, Tab 2, Schedule 4 and Exhibit 7, Tab 1, Schedule 1. The schedule of proposed rates is set out in Exhibit 1, Tab 1, Schedule 2 Appendix A and Exhibit 8 Tab 1 Schedule 6;

- Approval of the harmonization of OHL's distribution rates across two geographical areas served by OHL. The amalgamation of Orangeville Hydro Limited and Grand Valley Energy Inc., EB-2008-0053 was approved by the OEB on July 14, 2008. In the application OHL had indicated that it would file with the OEB an application to harmonize the rates of the two entities in a 2010 cost of service rate filing.

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

- Approval of the proposed loss factor as set out in Exhibit 4, Tab 2, Schedule 8;

- Approval of revised low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8, Tab 1, Schedule 1;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of OHL's 2009 Distribution Rates (EB-2008-0204). Approval of the Retail Transmission-Network Service and Retail Transmission-Connection rates subject to the Guideline Electricity Distribution Retail

Transmission Service (G-2008-0001) issued October 22, 2008, Revision 1.0 issued July 22, 2009;

- Any modifications as a result of the OEB's decision on Hydro One Networks' 2010 Uniform Transmission Rate Adjustment Application (OEB File EB-2008-072) effective January 1, 2010;

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of OHL's 2009 Distribution Rates (EB-2008-0204) and

- Approval to dispose of the following Deferral and Variance Account Balances audited December 31, 2008 with carrying charges calculated as at April 30, 2010 over a four-year period instead of the one-year period described in the Report of the Board dated July 31, 2009 (EB-2008-0046) using the method of recovery described in Exhibit 9, Tab 1, Schedule 3:

1508	Other Regulatory Assets-OMERS
1508	Other Regulatory Assets - Sub-account OEB Cost Assessments
1518	Retail Cost Variance Account
1548	Retail Cost Variance Account (STR)
1550	Low Voltage Variance
1570	Transition Costs Variance
1590	Regulatory Asset Recovery
1580	Wholesale Market Service Charges Variance
1582	One-Time Charges Variance
1584	Transmission Network Variance
1586	Transmission Connection Variance
1588	Power Variance

DRAFT ISSUES LIST:

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

- The amount of OHL's proposed revenue requirement; and
- The reasonableness of the 2010 capital program and the 2010; and
- The reasonableness of the 2010 operating, maintenance and administration budget; and
- The reasonableness of the 2010 weather-normalized forecast; and
- The reasonableness of the proposed harmonized electricity distribution rates; and
- The appropriateness of OHL's proposed cost allocation-related adjustments to class-specific revenue requirements, reflected in the proposed distribution rates; and
- The appropriateness of OHL's harmonization of Low Voltage charges

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On February 8, 2008, OHL filed a self-nomination request for rebasing in 2010. Subsequently, in Board File No. EB-2006-0330, the OEB issued its list of distributors that will be rebased in 2010. OHL was included on that list.

ACCOUNTING ORDERS REQUESTED:

OHL is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

OHL 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 Orangeville, Former Village of Grand Valley
TOTAL SERVICE AREA:	17 sq km
RURAL SERVICE AREA:	0 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	29,829
MUNICIPAL POPULATION:	29,829

A map of the OHL’s Distribution Service Territory accompanies this Schedule as Appendix B.

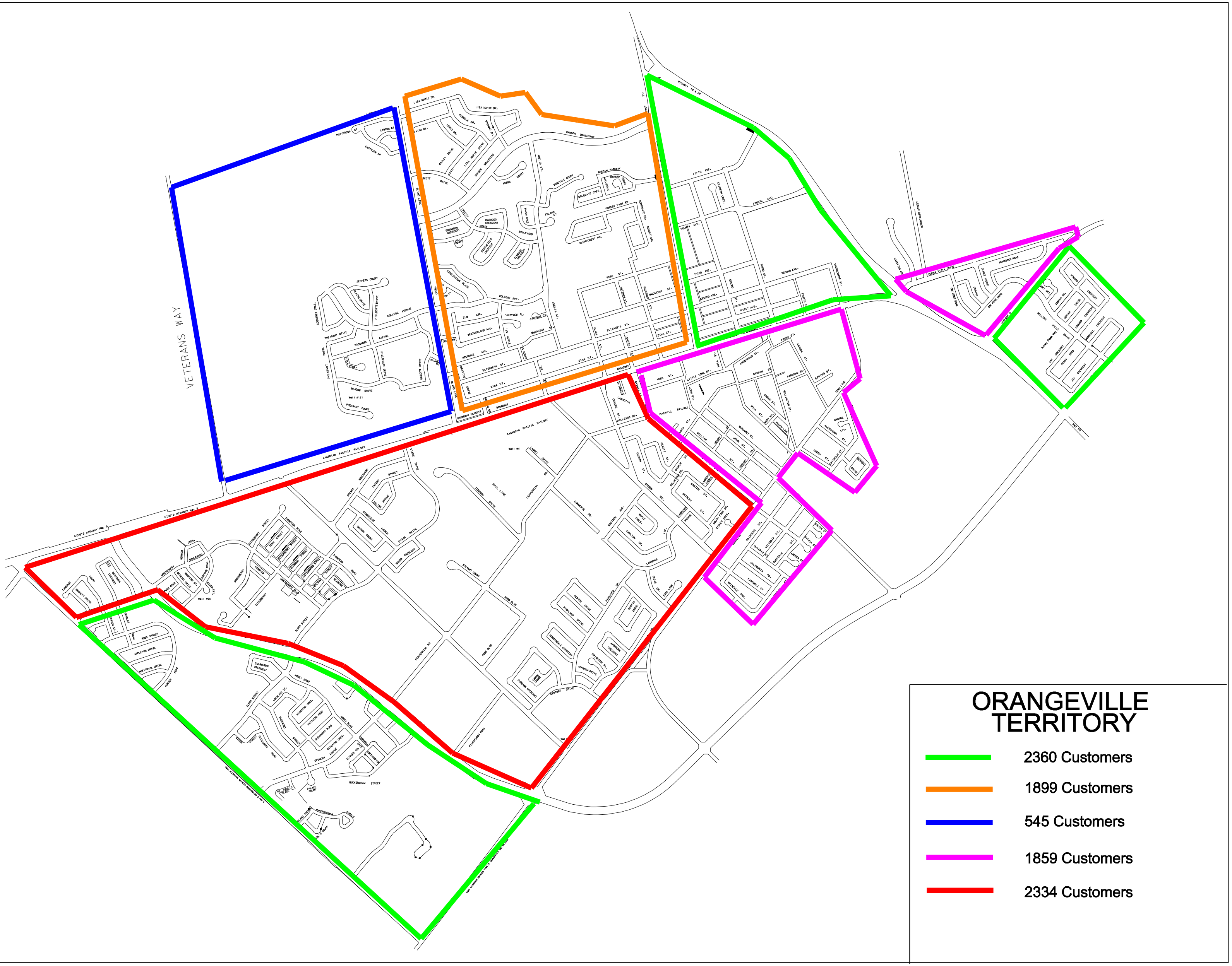
A schematic diagram of OHL’s distribution system is attached in Appendix C.

APPENDIX B

MAP OF DISTRIBUTION SERVICE TERRITORY

MAP OF DISTRIBUTION SERVICE TERRITORY

The outlined area represents the Town of Orangeville and the Village of Grand Valley.



ORANGEVILLE TERRITORY

🟩 2360 Customers

🟧 1899 Customers

🟦 545 Customers

🟪 1859 Customers

🟥 2334 Customers

GRAND VALLEY
TERRITORY

593 Customers

Orangeville Hydro Limited
EB-2009-0272
Exhibit 1
Tab 1
Schedule 10
Appendix C
Filed: August 28, 2009

APPENDIX C

MAP OF DISTRIBUTION SYSTEM

MAP OF Orangeville Hydro Limited DISTRIBUTION SYSTEM

ORANGEVILLE HYDRO SUBSTATIONS

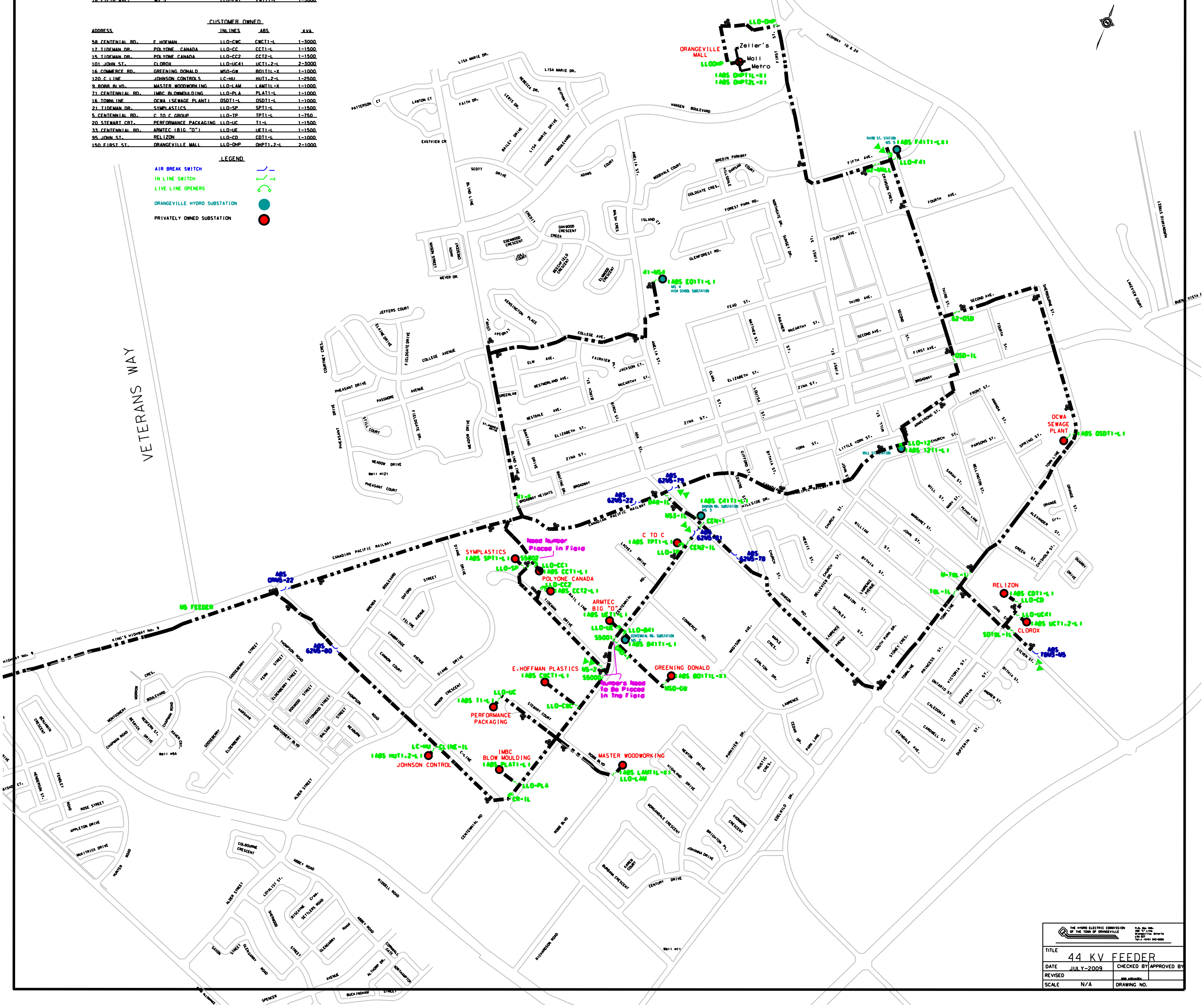
ADDRESS	SUBSTATION	OPENER	AIR BREAK SWITCH	KVA
40 MILL ST.	MS 1	LLO-12	12T1-L	3-1000
38 CENTENIAL RD.	MS 2	LLO-B41	B41T1-L	1-5000
9 DAWSON RD.	MS 3	LLO-C41	C41T1-L	1-5000
78 AMILIA ST.	MS 4	41-MS4	E01T1-L	1-5000
78 FIFTH AVE.	MS 5	LLO-F41	F41T1-L	1-5000

CUSTOMER OWNED

ADDRESS		INLINES	ABS	KVA
58 CENTENIAL RD.	E HOFMAN	LLO-CWC	CWCT1-L	1-3000
17 TIDEMAN DR.	POLYONE CANADA	LLO-CC	CCT1-L	1-1500
15 TIDEMAN DR.	POLYONE CANADA	LLO-CC2	CCT2-L	1-1500
101 JOHN ST.	CLOROX	LLO-UC41	UCT1,2-L	2-3000
16 COMMERCE RD.	GREENING DONALD	MSO-GW	B01T1L-X	1-1000
120 C LINE	JOHNSON CONTROLS	LC-HU	HUT1,2-L	1-2500
9 ROBB BLVD.	MASTER WOODWORKING	LLO-LAM	LAMT1L-X	1-1000
71 CENTENNIAL RD.	IMBC BLOWMOULDING	LLO-PLA	PLAT1-L	1-1000
16 TOWNLINE	OCWA (SEWAGE PLANT)	OSDT1-L	OSDT1-L	1-1000
21 TIDEMAN DR.	SYMPLASTICS	LLO-SP	SPT1-L	1-1500
5 CENTENNIAL RD.	C TO C GROUP	LLO-TP	TPT1-L	1-750
20 STEWART CRT.	PERFORMANCE PACKAGING	LLO-UC	T1-L	1-1500
33 CENTENNIAL RD.	ARMTEC (BIG "O")	LLO-UE	UET1-L	1-1500
95 JOHN ST.	RELIZON	LLO-CD	CDT1-L	1-1000
150 FIRST ST.	ORANGEVILLE MALL	LLO-OHP	OHPT1,2-L	2-1000

LEGEND

AIR BREAK SWITCH	_/ _
IN LINE SWITCH	⊢_/ ⊣
LIVE LINE OPENERS	⌒
ORANGEVILLE HYDRO SUBSTATION	●
PRIVATELY OWNED SUBSTATION	●

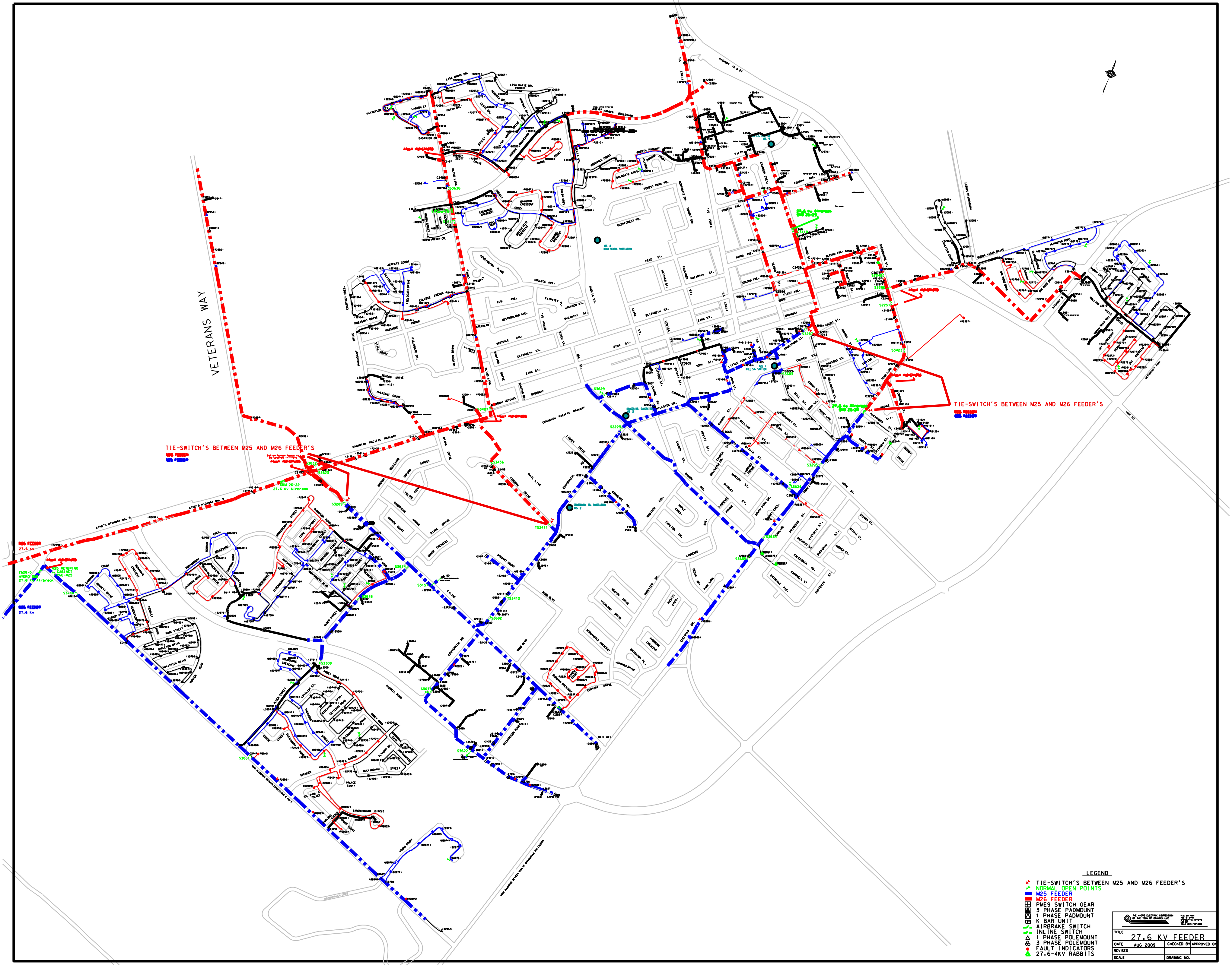


THE HYDRO ELECTRIC COMMISSION
OF THE TOWN OF ORANGEVILLE

P.O. Box 400,
400 "C" Line
Orangeville, Ontario
L9W 2Z7
Tel.: (519) 942-8000

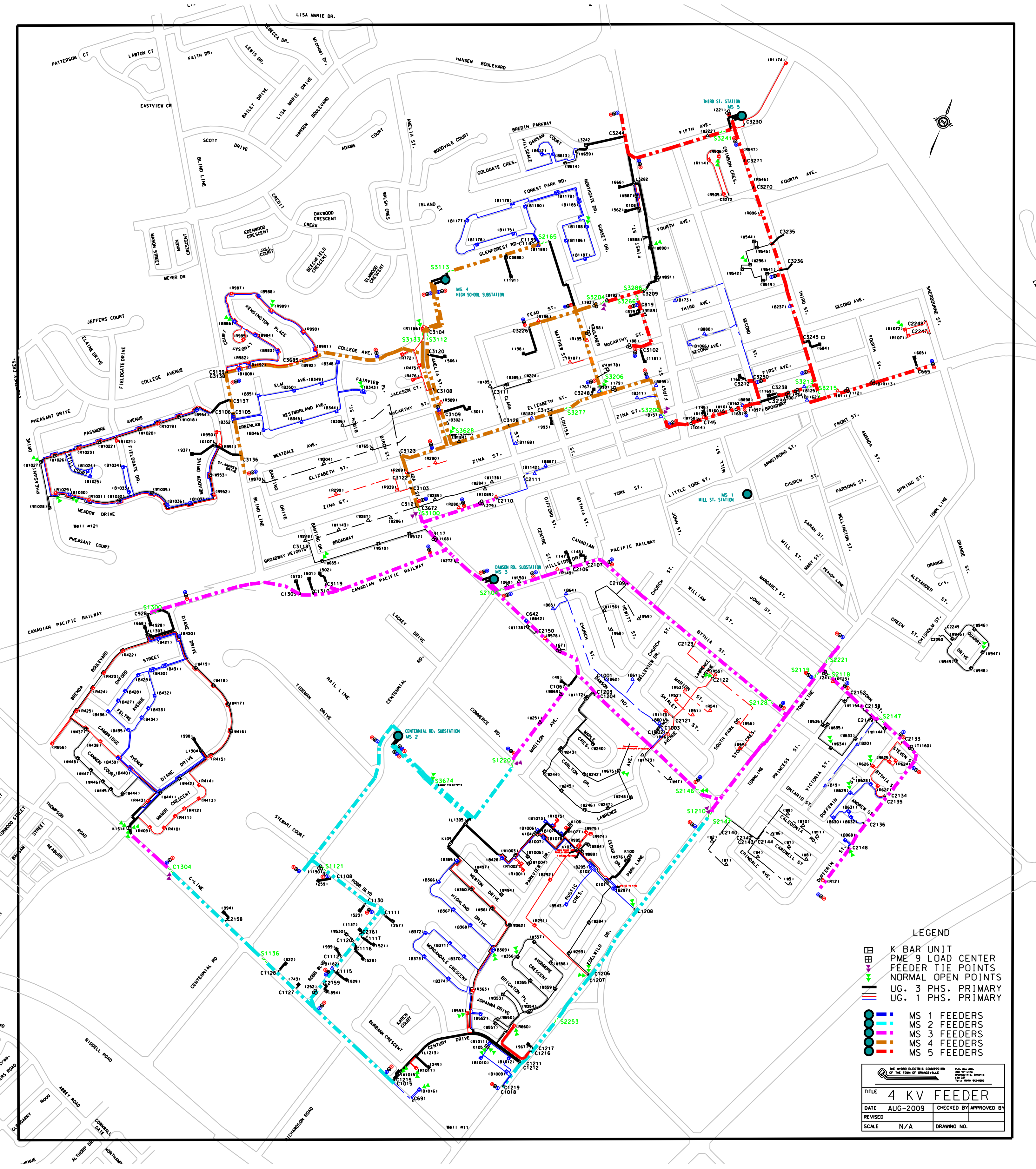
TITLE	44 KV FEEDER
DATE	JULY-2009
REVISED	
SCALE	N/A

CHECKED BY	APPROVED BY
ROB KOEKKOEK	
DRAWING NO.	



THE HYDRO ELECTRIC COMMISSION
OF THE TOWN OF ORANGEVILLE

TITLE	27.6 KV FEEDER		
DATE	AUG 2009	CHECKED BY	APPROVED BY
REVISED			
SCALE		DRAWING NO.	



THE HYDRO ELECTRIC COMMISSION OF THE TOWN OF ORANGEVILLE	P.O. Box 400, 400 "C" Line Orangeville, Ontario L9W 2Z7 Tel.: (519) 942-8000		
TITLE	4 KV FEEDER		
DATE	AUG-2009	CHECKED BY	APPROVED BY
REVISED			
SCALE	N/A	DRAWING NO.	

LIST OF NEIGHBOURING UTILITIES:

OHL is bounded by : Hydro One

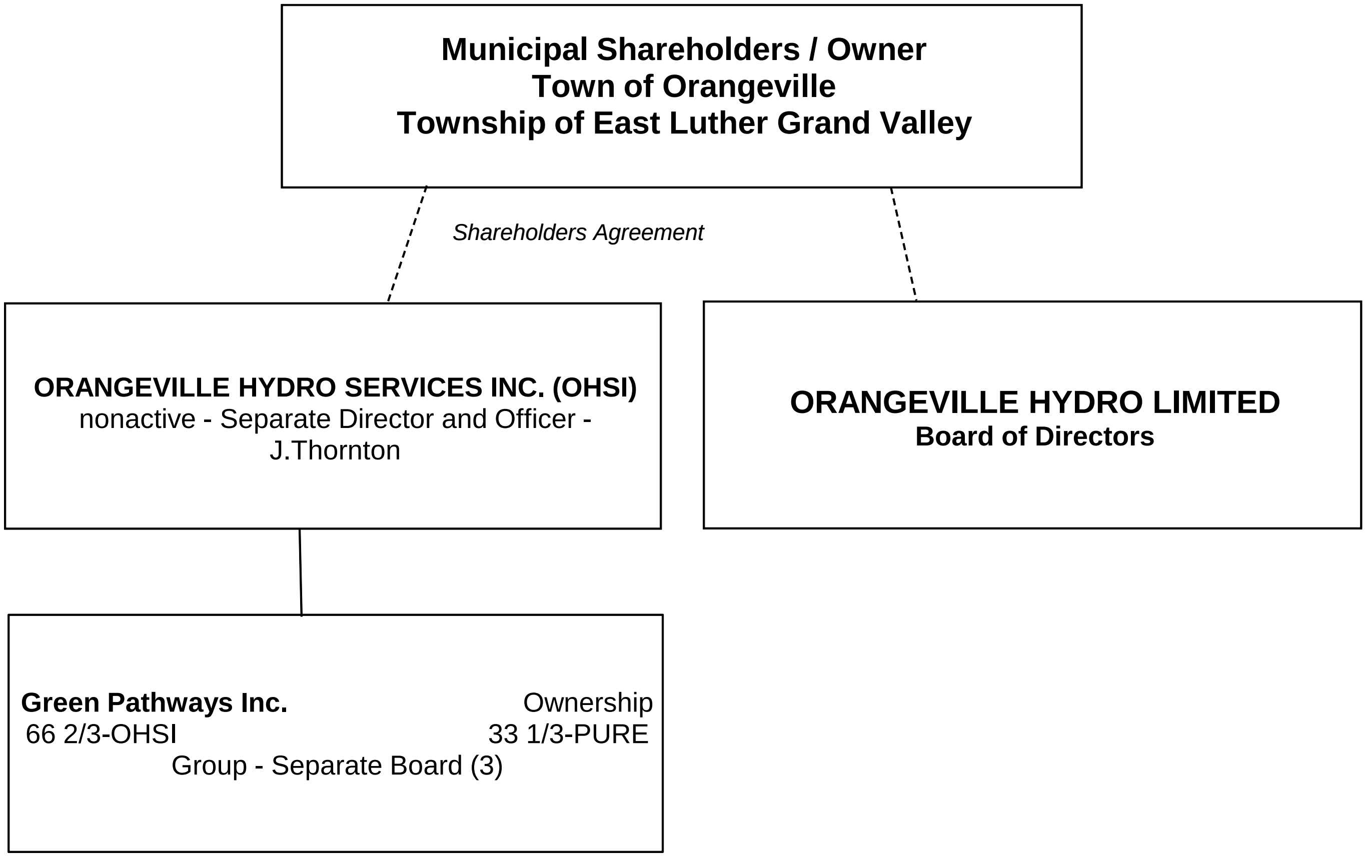
EXPLANATION OF HOST AND EMBEDDED UTILITIES:

There are no embedded utilities within OHL’s distribution service territory nor is OHL a host utility to other distributors.

UTILITY ORGANIZATIONAL STRUCTURE:

OHL is 94.5% owned by the Town of Orangeville and 5.5% owned by the Township of East Luther-Grand Valley. A chart illustrating OHL's corporate family is provided at Exhibit 1, Tab 1, Schedule 14.

CORPORATE ENTITIES RELATIONSHIP CHART



PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to OHL's corporate and operational structures are planned at the present time. However, OHL is reviewing recent changes to the Affiliate Relationships Code to determine if any changes to the corporate and operational structures are required.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

At this time there are no Board Directives from previous Board decisions.

CONDITIONS OF SERVICE:

A copy of OHL’s revised Conditions of Service was filed separately with the OEB on August 11, 2008. Per the draft filing requirements, the Conditions of Service are no longer required to be included in this document. A copy of the Conditions of Service is available on OHL’s website www.orangevillehydro.on.ca.

RECENT CHANGES IN CONDITIONS OF SERVICE:

A copy of the notice printed in the May 30, 2008 issue of the Orangeville Banner advising customers regarding planned changes to OHL’s Conditions of Service for August 11, 2008 implementation is set out in Appendix D to this Schedule.

IRON KIDS: The eighth annual Kinetico Caledon Kids of Steel triathlon, held Sunday at Caledon Central public school, attracted over 550 participants, including 92 children competing in the three to six age category and many of Ontario's finest junior athletes. In the six- and seven-year-old age group are, clockwise from top: Kiana Hudson navigates the course on her bike; Alyson McElhone was so determined to get to the finish line that she didn't bother to take her bike helmet off for the run; Elisabeth D'Almada from Hillsburgh and Darcey Steward from Erin show off their medals; and Lili Boyle finishes her run.

Mike Rawn - The Banner

ORANGEVILLE HYDRO

GRAND VALLEY ENERGY INC.

Notice of Change to Conditions of Service Document

The Distribution System Code requires that every distributor produce its own "Conditions of Service" document. The purpose of this document is to provide a means of communicating the types and level of service available to the customers within the distributor's service territory.

The current version of the Conditions of Service was published in 2004. Since then, various changes to regulations and codes that govern Distributor activities have come into effect, which in turn require updates to the original document.

The revised document is available to view on our web site, *www.orangevillehydro.on.ca* Customers without internet access may obtain a copy of the revised *Conditions of Service at our office at 400 C Line, Orangeville, ON.*

The public is invited to make written comments on the revisions. Comments will be accepted until Friday July 15, 2008. Please direct all written comments to:

Orangeville Hydro Limited
Grand Valley Energy
Attn: Conditions of Service
400 C Line
Orangeville, ON L9W 2Z7

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PRELIMINARY LIST OF WITNESSES:

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

SUMMARY OF THE APPLICATION:

Preamble

OHL has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Current rates will result in actual Return on Equity in 2009 and 2010 well below levels currently approved by the OEB. The increased rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.

2) Continue with training programs for line staff needed to meet future staffing requirements and prepare for succession planning.

3) Manage staffing levels and skills to ensure regulatory compliance, ESA compliance, promote conservation programs along with the introduction of smart meters, and implement reporting changes resulting from the adoption of International Financial Reporting Standards.

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

OHL's Mission Statement is:

To provide safe, reliable, efficient delivery of electrical energy within the Town of Orangeville while being accountable to our shareholders….the citizens of Orangeville.

OHL's Vision Statement is:

To be acknowledged as a leader among electric utilities in the areas of safety, reliability, customer service, financials and performance.

OHL's priorities are defined in its Corporate Goals:

> *To form partnerships and alliances with other local distribution companies. This will be accomplished through participating in the "Cornerstone Hydro-Electric Concepts" group.*
>
> *To invest heavily in our staff and rely on them to help us accomplish our goals by keeping staff informed, understand their expectations and their importance to the organization providing them with the tools, equipment and training.*
>
> *To stay current with industry, sector and regulatory changes.*
>
> *Orangeville Hydro has won 3 safety awards in the past and we will seek new ways to further enhance the safety of our employees, our customers and community.*
>
> *To pursue new business opportunities, partnerships and best management practices in our quest to meet or exceed financial expectations of our community by cost sharing, efficiency gains and cost savings.*
>
> *To investigate roles and opportunities that Orangeville Hydro Limited can pursue in generation and through conservation and demand management initiatives.*

In keeping with this vision to pursue health and safety as its top priority, OHL was recently awarded by the Electrical & Utilities Safety Association ("E&USA") the safety Bronze Award pursuit of ZeroQuest which represents zero injuries and illnesses.

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

OHL has consistently exceeded the OEB's Service Quality Indicators and, as set out in Table 1 below, has targeted to maintain its performance at levels equal to or above the OEB's standards in 2009 and 2010.

Table 1
OHL's SERVICE QUALITY INDICATORS
AVERAGE PERFORMANCE FOR 2007

Appointments Met – at the appointed time		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
100.00%	95.00%	95.00%
Telephone Accessibility – answered in person within 30 seconds		
SQI Standard: 65% of the time		
2008 Actual	**2009 Target**	**2010 Target**
100.00%	80.00%	80.00%
Underground Cable Locates – within 5 working days		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
100.00%	90.00%	90.00%
Connection of New Services –within 5 working days		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
100.00%	95.00%	95.00%
Emergency Response – Urban within 60 minutes and Rural within 120 minutes		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
100.00%	95.00%	95.00%
Written Responses to Inquiries – within 10 working days		
SQI Standard: 80% of the time		
2008 Actual	**2009 Target**	**2010 Target**
100.0%	90.00%	95.00%

Purpose and Need

OHL's requested revenue requirement for 2010 in the amount of $5,362,234 includes the recovery of its costs to provide distribution services, its permitted Return on Equity ["ROE"] and the funds necessary to service its debt as it transitions to a 60%/40% debt equity ratio by 2010.

When forecasted energy and demand levels for 2010 are considered, OHL estimates that its present rates will produce a deficiency in gross distribution revenue of **$631,388** for the 2010 Test Year. Should this revenue deficiency continue, OHL will not be able to sustain the current capital investment and lineperson training programs required to ensure a safe and reliable distribution system.

Therefore, OHL seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Tab 1, Schedule 6 to this Application.

The information presented in this Application is OHL's forecasted results for its 2010 Test Year. OHL is also presenting the historical actual information for fiscal 2006, OEB-Approved data for 2006, actual information for fiscal 2007, actual information for fiscal 2008, and forecast results for the 2009 Bridge Year.

Timing

The financial information supporting the Test Year for this Application will be OHL's fiscal year ending December 31, 2010 (the "2010 Test Year"). However, this information will be used to set rates for the period May 1, 2010 to April 30, 2011.

Customer Impact

In preparing this application, OHL has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, OHL notes that for the majority of its customers, the current revenue to cost ratio of each rate class does fall within the applicable threshold defined by the OEB in the November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors. OHL has updated the Cost Allocation model for the 2010 forecast year. As a result, adjustments have been made in this Application to bring all but Street Light and Sentinel Light classes within the allowed ranges of the revenue-to-cost ratios. Street Light and Sentinel Light classes are being increased by approximately 50% of the difference between their current levels and the bottom of the OEB's ranges, and OHL will further adjust the revenue-to-cost ratios in 2011 to bring them to the bottom of the approved ranges. Increased distribution revenue from these two classes in 2010 and 2011 will be offset by reductions in distribution revenue from the Residential class. Although this class is currently within the targeted revenue-to-cost ratio, the reductions in 2010 and 2011 will move the revenue-to-cost ratio closer to 100%.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised low voltage rates, the impact of harmonization of the rates of the two service areas revised loss factors, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application over a four-year period are set out in Table 2 below.

Smart Meters:

OHL is not requesting any revisions to the Smart Meter Rate Adder in this application.

Table 2
TOTAL BILL IMPACT – PERCENT & DOLLAR

Orangeville Service Area
Average Monthly Total Bill Impact - Percentage & Dollar Comparison 2009

Class Average Monthly Total Bill Impact	Average Total Bill Impact	Average Dollar Impact
Residential		
100 kWh	5.20%	$ 1.45
250 kWh	3.20%	$ 1.37
500 kWh	2.10%	$ 1.43
600 kWh	3.43%	$ 1.46
800 kWh	1.45%	$ 1.46
1,000 kWh	1.19%	$ 1.45
1,500 kWh	0.82%	$ 1.45
General Service < 50 kW		
2,000 kWh	1.78%	$ 4.23
4,000 kWh	1.01%	$ 4.53
10,000 kWh	0.50%	$ 5.42
12,500 kWh	0.43%	$ 5.80
15,000 kWh	0.38%	$ 6.17
General Service > 50 kW		
11,000 kWh, 50 kW	5.62%	$ 75.68
100,000 kWh, 250 kW	0.87%	$ 83.94
210,000 kWh, 360 kW	0.60%	$ 114.87
400,000 kWh, 800 kW	0.32%	$ 118.61
855,000 kWh, 1755 kW	0.19%	$ 147.19
Street Lighting		
141,912 kWh, 379 kW	26.44%	$ 3,607.13
54 kWh, .15 kW	28.33%	$ 1.40
Sentinal Lighting		
12,062 kWh, 32 kW	38.52%	$ 461.84
68 kWh, .18 kW	38.48%	$ 2.60
Unmetered Scattered Load		
32,685 kWh	9.92%	$ 327.41
214 kWh	-47.32%	$ (24.92)

Grand Valley Service Area
Average Monthly Total Bill Impact - Percentage & Dollar Comparison 2009

Class Average Monthly Total Bill Impact	Average Total Bill Impact	Average Dollar Impact
Residential		
100 kWh	15.23%	$ 3.89
250 kWh	7.30%	$ 3.01
500 kWh	2.90%	$ 1.96
600 kWh	3.28%	$ 1.39
800 kWh	0.40%	$ 0.40
1,000 kWh	-0.47%	$ (0.59)
1,500 kWh	-1.68%	$ (3.06)
General Service < 50 kW		
2,000 kWh	1.97%	$ 4.65
4,000 kWh	-0.76%	$ (3.46)
10,000 kWh	-2.49%	$ (27.81)
12,500 kWh	-2.73%	$ (37.95)
15,000 kWh	-2.89%	$ (48.09)
General Service > 50 kW		
2,175 kWh, 60 kW	-12.89%	$ (110.97)
6,450 kWh, 65 kW	-10.20%	$ (127.59)
15,280 kWh, 60 kW	-6.46%	$ (125.64)
40,000 kWh, 125 kW	-6.89%	$ (307.22)
47,000 kWh, 100 kW	-10.94%	$ (255.86)
Street Lighting		
8,863 kWh, 24 kW	-7.56%	$ (86.77)
58 kWh, .46 kW	-13.07%	$ (1.28)
Unmetered Scattered Load		
1,496 kWh	-25.99%	$ (57.09)
499 kWh	-26.96%	$ (19.81)

Capital Structure

OHL is requesting a change in its deemed capital structure. Specifically, OHL is requesting a decrease in the deemed equity ratio from 43.3% to 40.0% consistent with the third year of the phase-in of the shift in OHL's capital structure from 50% to 40% equity as outlined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report").

Return on Equity

OHL has assumed a return on equity of 8.01% consistent with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on March 8, 2009. OHL understands the OEB will be finalizing the return on equity for 2010 rates based on January 2010 market interest rate information.

Capital Expenditures

OHL continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. OHL will continue the 27.6 kV conversion from 4kV in older areas of Town and expects to upgrade the CT's at one of our wholesale meter points, replace fault indicators that required replacement during our asset management condition study and complete an optimization study. OHL anticipates expenditures for the Green Energy Act to enable the renewable generation coming on-line to meet the Minister's directive.

Operating and Maintenance Costs

OHL plans to hire a regulatory analyst to assist with regulatory accounting, regulatory interpretations and the requirement of OEB reporting and project such as rate filings, cost allocation and economic evaluations. OHL also plans to hire a junior engineer to implement and manage SCADA system and GIS system along with IT expertise. OHL has also considered costs for completing the cost of service rate application and IFRS requirements. Based on the OEB's *Comparison of Ontario Electricity Distributors Costs [EB-2006-0268]*, as updated with 2007

Data issued on June 25, 2009, OHL’s OM&A costs per customer compare favorably with its “Mid Size Southern Medium-High Undergrounding” cohort. In 2007, the average OM&A cost per customer for the cohort was $214.00 while OHL’s cost was $209.00. Over the 3-year average from 2005 to 2007, OHL’s cost was $183.00 while the average for the cohort was $208.00. Details of the calculations supporting this analysis are included in Appendix E to this Schedule.

Orangeville Hydro Limited
EB-2009-0272
Exhibit 1
Tab 2
Schedule 1
Appendix E
Filed: August 28, 2009

APPENDIX E

COMPARISON OF OHL's 2007 OM&A COSTS TO "Small Southern Medium-High Undergrounding with Rapid Growth" COHORT GROUPING

SUMMARY OF THE APPLICATION

Comparison of Orangeville Hydro Limited OM&A Costs To "Small Southern Medium-High Undergrounding with Rapid Growth" Cohort Grouping

Cohort Groupings	**Total OM&A**	
By Distribution Company	**2005-2007 3 Year Avg.**	**2007**
Grimsby Power Incorporated	$ 162.00	$ 169.00
Orangeville Hydro Limited	**$ 181.00**	**$ 192.00**
Cooperative Hydro Embrun Inc.	$ 202.00	$ 210.00
Niagara-on-the-Lake Hydro Inc.	$ 207.00	$ 227.00
Centre Wellington Hydro Ltd.	$ 239.00	$ 242.00
Average for Cohort Group	**$ 198.00**	**$ 208.00**

SOURCE:

Comparison of Ontario Electricity Distributors Costs [EB-2006-0268], updated with 2007 Data issued June 25, 2009.

BUDGET DIRECTIVES:

OHL compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2009 Bridge Year and the 2010 Test Year. The Board of Directors have reviewed and approved the 2009 and 2010 capital and OM&A budgets.

Revenue Forecast

OHL's energy sales and revenue forecast model was updated to reflect more recent information such as population economic conditions, average weather conditions and peak and off peak hours. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2009 and 2010. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, and Schedule 1 and considers such factors as new customer additions, customer class changes, and load profiles for all classes of customers.

Operating Maintenance and Administration (“OM&A”) Expense Forecast

The OM&A expenses for the 2009 Bridge Year and the 2010 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The capital budget forecast 2009 and 2010 is influenced, among other factors, by OHL’s capacity to finance capital projects. Indirect costs are allocated to direct costs in the capital budget. OHL is subject to coordinate works with Town projects in order to achieve economies of scope. All proposed capital projects are assessed within the framework of its capital budget priority and are outlined in Exhibit 2, Tab 3, and Schedule 3 (Capital Expenditures by Project).

CHANGES IN METHODOLOGY:

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

Calculation of Revenue Deficiency or Surplus

	2010 Test Existing Rates	2010 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$631,388
Distribution Revenue	$4,374,574	$4,374,574
Other Operating Revenue (Net)	$356,272	$356,272
Total Revenue	$4,730,846	$5,362,234
Distribution Costs		
Operation, Maintenance, and Administration	$2,769,015	$2,769,015
Depreciation & Amortization	$1,119,762	$1,119,762
Property & Capital Taxes	$2,099	$2,099
Interest- Deemed Interest	$652,936	$652,936
Total Costs and Expenses	$4,543,812	$4,543,812
Utility Income Before Income Taxes	$187,034	$818,422
Net Adjustments per 2009 Pils	$41,959	$41,959
Taxable Income	$228,993	$860,381
First $500,000	23.5%	23.5%
Remaining	36.25%	36.25%
Effective Tax Rate	8.41%	28.84%
Income Tax	$19,260	$248,138
Utility Net Income	$167,774	$570,284
Rate Base	$17,799,123	$17,799,123
Return on Equity	8.01%	8.01%
Equity Rate Base %	40.00%	40.00%
Equity Component Rate Base	$7,119,649	$7,119,649
Target Return -Equity on Rate Base	570,284	570,284
Revenue Deficiency	**$402,510**	**$0**
Revenue Deficiency (Gross-up)	**$631,388**	**$0**

CAUSES OF REVENUE DEFICIENCY:

OHL's net revenue deficiency is calculated as $402,510 and when grossed up for PILs, the revenue deficiency is $631,388. Orangeville Hydro Limited's calculation of its 2010 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 4 and Exhibit 7, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- Increases in OM&A costs including depreciation expense. OHL will be increasing staff with a new hire of a Regulatory person and a junior engineer commencing 2010. The addition of a Conservation and Demand Coordinator along with administrative skills in 2007 is necessary to meet the work load associated with conversation programs initiated by the Ontario Power Authority ("OPA"). OHL implemented a lineperson apprentice program in 2007 in order to ensure qualified lineman are in place for forecasted retirements in the next five years. OM&A cost are discussed in further detail in Exhibit 4; and an addition of a contracted position to implement SCADA.

- Capital Expenditures in 2006, 2007 and 2008 exceeded depreciation levels resulting in a increased rate base on which the rate of return is calculated. OHL is committed to ensuring the reliability of the distribution system and will continue to invest in capital infrastructure in 2009 and 2010. Changes in the Rate Base are discussed further in Exhibit 2.

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

FINANCIAL STATEMENTS –2007 & 2008:

OHL’s Audited Financial Statements accompany this Schedule as Appendix F.

Orangeville Hydro Limited
EB-2009-0272
Exhibit 1
Tab 3
Schedule 1
Appendix F
Filed: August 28, 2009

APPENDIX F

COPY OF AUDITED FINANCIAL STATEMENTS FOR 2007 & 2008

Orangeville Hydro Limited

Financial Statements

For the year ended December 31, 2007

Orangeville Hydro Limited
Financial Statements
For the year ended December 31, 2007

Contents

BDO
Driving growth

BDO Dunwoody LLP
Chartered Accountants
and Advisors

77 Broadway, 2nd Floor
Orangeville, Ontario, Canada L9W 1K1
Telephone: (519) 941-0681
Fax: (519) 941-8272

Auditors' Report

To the Shareholder of
Orangeville Hydro Limited

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

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company 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.

BDO Dunwoody LLP

Chartered Accountants, Licensed Public Accountants

Orangeville, Ontario
February 28, 2008

Orangeville Hydro Limited
Balance Sheet

December 31	2007	2006
Assets		
Current		
Cash	**$ 1,315,135**	$ 3,274,791
Accounts receivable	**2,727,540**	2,827,229
Inventory	**323,303**	458,827
Accrued unbilled revenue	**1,696,635**	1,648,616
Payments in lieu of income taxes receivable	**143,645**	-
Other current assets	**204,396**	119,349
	6,410,654	8,328,812
Capital assets (Note 2)	**12,934,062**	12,927,125
	$ 19,344,716	$ 21,255,937
Liabilities and Shareholder's Equity		
Current		
Accounts payable and accrued liabilities	**$ 2,986,657**	$ 2,822,103
Payments in lieu of income taxes payable	**-**	14,963
Current portion of consumer deposits	**25,000**	25,000
Current portion of long-term debt (Note 5)	**185,981**	600,000
Current portion of regulatory liabilities (Note 3)	**34,894**	81,264
Other current liabilities	**202,705**	177,645
	3,435,237	3,720,975
Long-term debt (Note 5)	**6,243,417**	7,200,000
Regulatory liabilities (Note 3)	**1,150,665**	1,236,672
Post-employment benefits (Note 8)	**152,331**	128,621
Consumer deposits	**487,812**	461,019
	11,469,462	12,747,287
Contingency (Note 13)		
Shareholder's equity		
Share capital (Note 7)	**7,815,535**	7,815,535
Retained earnings (Page 4)	**59,719**	693,115
	7,875,254	8,508,650
	$ 19,344,716	$ 21,255,937

On behalf of the Board:

____________________ Director ____________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Orangeville Hydro Limited
Statement of Operations and Retained Earnings

For the year ended December 31	**2007**	2006
Service revenue	**$ 22,119,800**	$ 21,358,535
Cost of power	**18,006,331**	17,316,878
Gross margin on service revenue	**4,113,469**	4,041,657
Other operating revenue	**556,052**	480,179
Gross margin	**4,669,521**	4,521,836
Operating and maintenance expenses		
Distribution	**682,534**	552,034
Billing and collection	**418,609**	435,398
General and administrative	**988,583**	865,974
Amortization	**929,960**	885,464
Financial	**489,483**	564,248
	3,509,169	3,303,118
Income before payments in lieu of income taxes	**1,160,352**	1,218,718
Payments in lieu of income taxes (Note 4)	**513,187**	579,144
Net income for the year	**647,165**	639,574
Retained earnings, beginning of year	**693,115**	364,321
Dividends	**(1,280,561)**	(310,780)
Retained earnings, end of year	**$ 59,719**	$ 693,115

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Orangeville Hydro Limited
Statement of Cash Flows

For the year ended December 31	2007	2006
Cash provided by (used in)		
Operating activities		
Net income	**$ 647,165**	$ 639,574
Items not involving cash		
Amortization of capital assets	**1,042,416**	990,574
Gain on disposal of capital assets	**(5,565)**	(7,915)
Increase in post-employment benefits	**23,710**	22,646
	1,707,726	1,644,879
Changes in non-cash working capital balances		
Accounts receivable	**99,689**	(938,850)
Inventory	**135,524**	(104,859)
Accrued unbilled revenue	**(48,019)**	227,298
Payments in lieu of income taxes receivable	**(143,645)**	-
Other current assets	**(85,047)**	(13,837)
Accounts payable and accrued liabilities	**164,554**	(173,767)
Payments in lieu of income taxes payable	**(14,963)**	(86,334)
Current portion of regulatory liabilities	**(46,370)**	6,405
Other current liabilities	**25,060**	(62,104)
	86,783	(1,146,048)
Net change in non-current balance sheet items	**(59,214)**	(5,951)
	1,735,295	492,880
Investing activities		
Purchase of capital assets	**(1,584,588)**	(1,485,150)
Proceeds on sale of capital assets	**5,940**	18,443
	(1,578,648)	(1,466,707)
Financing activities		
Advance of long-term debt	**6,500,000**	-
Repayment of long-term debt	**(7,870,602)**	(600,000)
Dividends	**(1,280,561)**	(310,780)
Capital contributions received	**534,860**	226,554
	(2,116,303)	(684,226)
Decrease in cash during the year	**(1,959,656)**	(1,658,053)
Cash, beginning of year	**3,274,791**	4,932,844
Cash, end of year	**$ 1,315,135**	$ 3,274,791

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Basis of Presentation

The financial statements have been prepared in accordance with accounting principles for municipal electrical utilities in Ontario as required by the Ontario Energy Board under authority of Section 57, 70(2) and 78 of the Ontario Energy Board Act, 1998 and reflect the policies as set forth in the "Accounting Procedures Handbook." All principles employed are in accordance with Canadian generally accepted accounting principles.

Nature of Business

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity. The Distributor is licensed by the Ontario Energy Board (OEB) to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act. The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

Use of Estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

Effective January 1, 2007, the company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook sections 1530 - *Comprehensive Income*, 3855 - *Financial Instruments - Recognition and Measurement* and 3861 - *Financial Instruments - Disclosure and Presentation*. As provided under the standards, the comparative financial statements have not been restated. Relevant changes as a result of these new Handbook sections on the accounting for financial instruments are outlined below.

Comprehensive Income

Section 1530 describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income (OCI). OCI represents changes in the fair value of a financial instrument which have not been included in net income. The company had no adjustments to other comprehensive income during the year ended December 31, 2007; therefore, the adoption of this standard does not have an impact on the financial statements.

Financial Instruments - Recognition and Measurement

Section 3855 describes the recognition and measurement requirements for financial assets and financial liabilities. On initial recognition, all financial instruments that meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Subsequent measurement depends on whether the financial instrument has been classified as “held-for-trading”, “available-for-sale”, “held-to-maturity”, “loans and receivables” or “other financial liabilities”. As of January 1, 2007, the company has elected the following balance sheet classifications with respect to its financial assets and financial liabilities.

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

Accounts receivable and accrued unbilled revenue are classified as “loans and receivables” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Accounts payable and accrued liabilities and long-term debt are classified as “other financial liabilities” and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

These new standards were applied as at January 1, 2007 and did not have any impact on the financial statements.

Management's opinion is that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments.

Corporate Income Taxes

The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered by the customers of the company at that time.

Inventory

Inventory is stated at the lower of cost and net realizable value. Cost is determined on an average cost basis.

Capital Assets

Capital assets are stated at cost less accumulated amortization. Cost is net of related investment tax credits and government grants. Amortization based on the estimated useful life of the asset is calculated using the straight-line method over the following number of years:

Buildings	50 years
Computer equipment	5 years
Computer software	5 years
Distribution stations	30 years
Distribution system	25 years
Land rights	25 years
Meters	25 years
Office equipment	10 years
Rolling stock	5 - 8 years
Sentinel lights	10 years
Stores equipment	10 years
Tools and equipment	10 years
Transformers	25 years

Orangeville Hydro Limited
Summary of Significant Accounting Policies

December 31, 2007

Consumer Deposits

Consumer deposits are cash collections from customers to guarantee the payment of energy bills. The consumer deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

Regulatory Assets/Liabilities

Regulatory assets/liabilities represent costs/receipts that have been deferred according to OEB regulatory guidelines. Regulatory assets/liabilities are reflected on the balance sheet until the manner and timing of disposition is determined by the OEB.

Post Employment Benefits for Employees

The company accrues its obligations under employee benefit plans and the related costs, net of plan assets if any. The company has adopted the following policy:

The cost of retirement benefits earned by employees is actuarially determined using the projected unit method pro-rated on service and management's best estimate of retirement ages of employees and expected health care costs.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The excess of net actuarial gain (loss) over 10% of the benefit plan obligation is amortized over the average remaining service period of active employees.

Revenue

Revenue is recognized in the financial statements on the accrual basis when the energy is supplied to the users, whether billed or unbilled.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

Capital Disclosures

CICA Handbook Section 1535, Capital Disclosures, requires disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements and, if the company has not complied, the consequences of such non-compliance. This standard is effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. The company is currently assessing the impact of the new standard.

Inventories

The CICA has issued Section 3031, Inventories, which provides guidance on determining cost and other recognition, measurement, disclosure and presentation issues related to inventories. The standard includes guidance on the treatment of excess capacities, inventory valuation and write-downs and additional elements to be considered in measuring inventory costs. The new standard is effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. The company is currently assessing the impact of the new standard.

Future Income Taxes

CICA Handbook Section 3465, Income Taxes, requires that rate regulated entities recognize future income taxes and a separate asset or liability for the future revenue or reduction in revenue expected as a result of a company's action in respect of future income taxes for fiscal years beginning on or after January 1, 2009. The company is currently assessing the impact of this standard.

International Financial Reporting Standards

The CICA plans to converge Canadian GAAP with International Financial Reporting Standards (IFRS) over a transition period expected to end in 2011. The impact of the transition to IFRS on the company's financial statements has yet to be determined.

1. Comparative Amounts

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

2. Capital Assets

	2007		2006	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Land	**$ 212,281**	**$ 12,190**	$ 208,325	$ 10,837
Buildings	**2,620,518**	**727,581**	2,452,467	683,291
Services	**2,144,587**	**1,222,536**	2,046,324	1,131,120
Distribution lines - overhead	**7,079,361**	**3,881,985**	6,856,617	3,635,804
Distribution lines - underground	**6,391,113**	**2,887,107**	5,913,988	2,644,751
Distribution meters	**1,701,317**	**881,241**	1,565,934	822,914
Distribution stations	**848,022**	**517,791**	823,258	492,237
Distribution transformers	**6,849,283**	**3,012,218**	6,519,816	2,772,546
Other capital assets	**1,910,373**	**1,422,246**	1,840,765	1,270,544
	29,756,855	**14,564,895**	28,227,494	13,464,044
Contributions and grants	**(2,832,170)**	**(574,272)**	(2,297,310)	(460,985)
	$ 26,924,685	**$ 13,990,623**	$ 25,930,184	$ 13,003,059
Net book value		**$ 12,934,062**		$ 12,927,125

3. Regulatory Assets (Liabilities)

Qualifying transition costs are costs incurred related to the preparations required for market opening. In accordance with Ontario Energy Board (OEB) guidelines, expenditures were allowed to be deferred during the period January 1, 2000 to December 31, 2002, which would be capitalized or expensed under Canadian generally accepted accounting principles for unregulated businesses. For the period January 1, 2003 to December 31, 2007, transition costs were increased by OEB-prescribed carrying charges.

The energy market in Ontario opened to competition on May 1, 2002. Since May 1, 2002, the difference between the cost of power based on time-of-use rates and amounts billed to non-time-of-use customers charged at an average rate are recorded in settlement variance accounts as directed by the OEB. These variance accounts ensure that a utility's gross profit is limited to distribution revenue and service charges.

The regulatory assets recovery account (RARA) includes regulatory asset balances the OEB has approved for recovery. This approved balance will be recovered over a period ending March 31, 2008. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges.

	2007	2006
Regulatory assets (liabilities)		
Qualifying transition costs	**$ (11,746)**	$ (11,405)
Settlement variances	**(938,830)**	(595,743)
Regulatory assets recovery account	**(167,038)**	(561,579)
	(1,117,614)	(1,168,727)
Regulatory liabilities - low voltage	**(67,945)**	(149,209)
	(1,185,559)	(1,317,936)
Current portion of regulatory (liabilities)	**(34,894)**	(81,264)
Net regulatory (liabilities)	**$ (1,150,665)**	$ (1,236,672)

4. Income Taxes

The provision for income taxes differs from the result which would be obtained by applying the combined Canadian Federal and Provincial Statutory income tax rates to income before income taxes. This difference results from the following items:

	2007	2006
Income before income taxes	**$ 1,160,352**	$ 1,218,718
Statutory income tax rate	**36.12** %	36.12 %
Expected income tax expense	**419,119**	440,201
Increase (decrease) in taxes resulting from:		
Permanent differences	**(5,385)**	(6,373)
Amortization in excess of capital cost allowance	**72,099**	93,494
Pre-market opening energy variances	**39,955**	39,955
Other	**8,535**	11,867
Prior year amendments	**(21,136)**	-
Income tax expense	**$ 513,187**	$ 579,144

5. Long-term Debt

	2007	2006
Term loan payable - TD Bank, 5.59%, due 2017, repayable in monthly payments of $45,048 principal and interest.	**$ 6,429,398**	$ -
Term loan payable - Scotiabank, 5.77%, due 2014, repayable in monthly interest instalments and annual principal payments of $600,000.	**-**	7,800,000
Less amounts due within one year included in current liabilities	**185,981**	600,000
	$ 6,243,417	$ 7,200,000

The agreement with respect to the TD Bank term loan contains certain covenants regarding (i) leverage, (ii) liquidity, (iii) restrictions on business activities, (iv) restrictions on distributions, (v) change in ownership, (vi) mergers, acquisitions or change in line of business and (vii) limitations on additional debt and encumbrance of assets.

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

2008	$ 185,981
2009	195,688
2010	206,912
2011	218,779
2012	230,432
Thereafter	5,391,606
	$ 6,429,398

The interest on long-term debt during the year amounted to $412,342 and is included in financial expense.

6. Related Party Transactions

The Town of Orangeville is the sole shareholder of the company. The company provides water and sewage billing and collection services to the customers of the Town as well as supplying streetlighting energy and streetlighting maintenance services to the Town.

The following table summarizes the company's related party transactions for the year:

	2007	2006
Revenue		
Sales to parent company	**$ 367,109**	$ 371,156

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

Included in accounts payable at December 31, 2007 is $556,042 (2006 - $501,777) payable to the Town.

Included in accounts receivable at December 31, 2007 is $71,756 (2006 - $78,366) receivable from the Town.

7. Share Capital

The authorized common share capital of the company is an unlimited number of shares.

The issued share capital is as follows:

		2007	2006
100	Common shares	**$ 7,815,535**	$ 7,815,535

8. Pension Agreement and Post Employment Benefits

(a) Pension Agreement

The company makes contributions to the Ontario Municipal Employees Retirement Fund (OMERS), which is a multi-employer plan, on behalf of members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The amount contributed to OMERS for the year ending December 31, 2007 was $86,765 (2006 - $156,299) for current service. There is no liability for past service.

(b) Post Employment Benefits

The company has a post employment benefit plan for its employees. Under the terms of the plan, employees are eligible for extended health care and dental benefits upon retirement or termination after age 55 until age 65. The latest actuarial valuation of the benefit plan, as of December 31, 2004, estimated the post employment benefit liability to be $84,213. The actuarial valuation for the year ended December 31, 2007 has not yet been completed. The accrued benefit obligation is estimated to be $244,600. The company is amortizing the past service costs arising from the initiation of this plan over the remaining service life of the employees which was 11 years as of December 31, 2004.

	2007	2006
Accrued benefit obligation	**$ 244,600**	$ 234,072
Less unamortized past service costs	**92,269**	105,451
Benefit plan obligation	**$ 152,331**	$ 128,621
Benefit plan expense	**$ 36,595**	$ 35,563
Less benefit plan payments	**12,885**	12,917
Net plan expense	**$ 23,710**	$ 22,646

The significant assumptions adopted in estimating the utility's accrued benefit obligation are as follows:

Discount rate	5.5%	
General inflation	2.2%	
Medical benefits cost escalation - extended health	10%	decreasing by 1% each year for 5 years
Dental benefits cost escalation	5%	
Salary rate increase	3.5%	

9. Public Liability Insurance

The company is a member of The Electrical Distributors Association Reciprocal Insurance Exchange which is a pooling of the public liability insurance risks of many of the municipal utilities in Ontario. All members of the pool are subject to assessment for losses experienced by the pool for the years in which they are members on a pro-rata basis based on the total of their respective service revenues.

It is anticipated that, should such an assessment occur, it would be funded over a period of up to five years. To December 31, 2007, no assessments have been made with respect to 2007 or prior years.

10. Subdivision Agreements

As part of various subdivision agreements, the company has received letters of credit to cover developers' responsibilities in completing the projects. Letters of credit held by the company at December 31, 2007 amount to $414,448 (2005 - $312,189).

11. Future Income Taxes

Future income taxes have not been recognized in these financial statements. Section 3465 of the CICA handbook does not require rate regulated enterprises to recognize future income taxes if future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. The estimated future income tax asset that has not been recognized as at December 31, 2007 is $470,000 (2006 - $450,000).

12. Statement of Cash Flows

	2007	2006
Interest paid	**$ 422,189**	$ 564,248
Payments in lieu of income taxes	**$ 683,038**	$ 689,948

13. Contingency

A class action is seeking $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities (LDCs) who received late payment charges from customers that were in excess of the interest limit stipulated in 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 since the parties were awaiting the outcome of 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. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the 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.

It is not possible at this time to quantify the effect, if any, of this action on the financial statements of the company.

14. Subsequent Event

The company entered into an agreement on December 3, 2007 to merge with Grand Valley Energy Inc. for the purpose of providing electricity distribution services in the Towns of Orangeville and Grand Valley as a single corporate entity. The merger is anticipated to occur in 2008 pending approval by the Ontario Energy Board.

December 31, 2007

15. Contractual Obligations

The company has a letter of credit of $832,229 issued in favour of the Independent Electricity System Operator (IESO). No amounts have been drawn as at December 31, 2007.

16. Dividends

Subject to applicable law, shareholder direction provided that the company would pay dividends to the Town of Orangeville in December of each year in the amount of 50% of the company's projected annual net income. Additional dividends may be applicable as long as the financing covenants are met and regulatory compliance is maintained. During 2007, the board of directors of the company declared and paid dividends totaling $1,280,561 to the Town (2006 - $310,780).

Covenants in the company's financing agreements state that no dividends, withdrawals, bonuses, advances to shareholders, management or affiliates are permitted that would place any bank credit conditions in default.

Grand Valley Energy Inc.

Financial Statements
For the year ended December 31, 2007

Grand Valley Energy Inc.
Financial Statements
For the year ended December 31, 2007

Contents

BDO

BDO Dunwoody LLP
Chartered Accountants
and Advisors

77 Broadway, 2nd Floor
Orangeville, Ontario, Canada L9W 1K1
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Fax: (519) 941-8272

Auditors' Report

To the Shareholder of
Grand Valley Energy Inc.

We have audited the balance sheet of Grand Valley Energy Inc. as at December 31, 2007 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company 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.

BDO Dunwoody LLP

Chartered Accountants, Licensed Public Accountants

Orangeville, Ontario
February 28, 2008

Grand Valley Energy Inc.
Balance Sheet

December 31		2007		2006
Assets				
Current				
Cash	**$**	**88,862**	$	58,784
Short-term investments (Note 2)		**67,428**		115,006
Accounts receivable		**153,943**		174,804
Inventory		**-**		905
Prepaid expenses		**3,341**		6,173
Accrued unbilled revenue		**59,025**		57,230
Payments in lieu of income taxes recoverable		**-**		5,988
Other current assets		**3,264**		5,834
		375,863		424,724
Capital assets (Note 3)		**312,367**		317,070
Regulatory assets (Note 4)		**-**		32,684
	$	**688,230**	$	774,478
Liabilities and Shareholder's Equity				
Current				
Accounts payable and accrued liabilities	**$**	**137,639**	$	154,010
Current portion of consumer deposits		**3,000**		3,000
Current portion of regulatory liabilities (Note 4)		**23,298**		40,909
Other current liabilities		**9,004**		7,310
		172,941		205,229
Regulatory liabilities (Note 4)		**17,022**		-
Consumer deposits		**14,810**		10,700
		204,773		215,929
Contingencies (Note 11)				
Shareholder's equity				
Share capital (Note 6)		**100**		100
Contributed surplus		**436,871**		436,871
Retained earnings (Page 4)		**46,486**		121,578
		483,457		558,549
	$	**688,230**	$	774,478

On behalf of the Board:

____________________ Director ____________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Grand Valley Energy Inc.
Statement of Operations and Retained Earnings

For the year ended December 31	2007	2006
Service revenue	**$ 952,481**	$ 920,768
Cost of power	**725,993**	681,557
Gross margin on service revenue	**226,488**	239,211
Other operating revenue	**29,434**	34,798
Gross margin	**255,922**	274,009
Operating and maintenance expenses		
Distribution	**34,092**	36,138
Billing and collection	**64,979**	41,262
General and administrative	**133,070**	165,292
Amortization	**42,798**	41,915
Financial	**1,075**	7,247
	276,014	291,854
Loss for the year	**(20,092)**	(17,845)
Retained earnings, beginning of year	**121,578**	139,423
Dividends	**(55,000)**	-
Retained earnings, end of year	**$ 46,486**	$ 121,578

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Grand Valley Energy Inc.
Statement of Cash Flows

For the year ended December 31	**2007**	2006
Cash provided by (used in)		
Operating activities		
Net loss	**$ (20,092)**	$ (17,845)
Items not involving cash		
Amortization of capital assets	**42,798**	41,915
	22,706	24,070
Changes in non-cash working capital balances		
Accounts receivable	**20,861**	(124,077)
Inventory	**905**	-
Prepaid expenses	**2,832**	(1,186)
Accrued unbilled revenue	**(1,795)**	118,478
Other current assets	**2,570**	(5,834)
Accounts payable and accrued liabilities	**(16,371)**	(13,803)
Payments in lieu of income taxes recoverable	**5,988**	-
Current portion of regulatory liabilities	**(17,611)**	393
Other current liabilities	**1,694**	(15,807)
	(927)	(41,836)
Net change in non-current balance sheet items	**53,816**	(18,513)
	75,595	(36,279)
Investing activities		
Purchase of capital assets	**(38,095)**	(30,072)
Net proceeds on sale of investments	**47,578**	21,926
	9,483	(8,146)
Financing activities		
Dividends	**(55,000)**	-
Increase (decrease) in cash during the year	**30,078**	(44,425)
Cash, beginning of year	**58,784**	103,209
Cash, end of year	**$ 88,862**	$ 58,784

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Basis of Presentation

The financial statements have been prepared in accordance with accounting principles for municipal electrical utilities in Ontario as required by the Ontario Energy Board under authority of Section 57, 70(2) and 78 of the Ontario Energy Board Act, 1998 and reflect the policies as set forth in the "Accounting Procedures Handbook." All principles employed are in accordance with Canadian generally accepted accounting principles.

Nature of Business

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity. The Distributor is licensed by the Ontario Energy Board (OEB) to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act. The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

Use of Estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

Effective January 1, 2007, the company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook sections 1530 - *Comprehensive Income*, 3855 - *Financial Instruments - Recognition and Measurement* and 3861 - *Financial Instruments - Disclosure and Presentation*. As provided under the standards, the comparative financial statements have not been restated. Relevant changes as a result of these new Handbook sections on the accounting for financial instruments are outlined below.

Comprehensive Income

Section 1530 describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income (OCI). OCI represents changes in the fair value of a financial instrument which have not been included in net income. The company had no adjustments to other comprehensive income during the year ended December 31, 2007; therefore, the adoption of this standard does not have an impact on the financial statements.

Financial Instruments - Recognition and Measurement

Section 3855 describes the recognition and measurement requirements for financial assets and financial liabilities. On initial recognition, all financial instruments that meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Subsequent measurement depends on whether the financial instrument has been classified as “held-for-trading”, “available-for-sale”, “held-to-maturity”, “loans and receivables” or “other financial liabilities”. As of January 1, 2007, the company has elected the following balance sheet classifications with respect to its financial assets and financial liabilities.

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

Short-term investments are classified as “held-to-maturity” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value.

Accounts receivable and accrued unbilled revenue are classified as “loans and receivables” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Accounts payable and accrued liabilities are classified as “other financial liabilities” and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

These new standards were applied as at January 1, 2007 and did not have any impact on the financial statements.

Management's opinion is that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments.

Corporate Income Taxes

The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered by the customers of the company at that time.

Inventory

Inventory is stated at the lower of cost and net realizable value. Cost is determined on an average cost basis.

Capital Assets

Capital assets are stated at cost less accumulated amortization. Cost is net of related investment tax credits and government grants. Amortization based on the estimated useful life of the asset is calculated using the straight-line method over the following number of years:

Computer equipment	5 years
Computer software	5 years
Distribution stations	30 years
Distribution system	25 years
Meters	25 years
Office equipment	10 years
Rolling stock	5 - 8 years
Sentinel lights	10 years
Stores equipment	10 years
Tools and equipment	10 years
Transformers	25 years

Grand Valley Energy Inc.
Summary of Significant Accounting Policies

December 31, 2007

Consumer Deposits

Consumer deposits are cash collections from customers to guarantee the payment of energy bills. The consumer deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

Regulatory Assets/Liabilities

Regulatory assets/liabilities represent costs/receipts that have been deferred according to OEB regulatory guidelines. Regulatory assets/liabilities are reflected on the balance sheet until the manner and timing of disposition is determined by the OEB.

Revenue

Revenue is recognized in the financial statements on the accrual basis when the energy is supplied to the users, whether billed or unbilled.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

Capital Disclosures

CICA Handbook Section 1535, Capital Disclosures, requires disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements and, if the company has not complied, the consequences of such non-compliance. This standard is effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. The company is currently assessing the impact of the new standard.

Future Income Taxes

CICA Handbook Section 3465, Income Taxes, requires that rate regulated entities recognize future income taxes and a separate asset or liability for the future revenue or reduction in revenue expected as a result of a company's action in respect of future income taxes for fiscal years beginning on or after January 1, 2009. The company is currently assessing the impact of this standard.

International Financial Reporting Standards

The CICA plans to converge Canadian GAAP with International Financial Reporting Standards (IFRS) over a transition period expected to end in 2011. The impact of the transition to IFRS on the company's financial statements has yet to be determined.

1. Comparative Amounts

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

2. Short-term Investments

	2007	2006
Royal Bank, one year cashable GIC, due November 2007, 3.15%	**$ -**	$ 50,000
Equitable Trust, five year annual GIC, due October 2010, 3.86%	**67,428**	65,006
	$ 67,428	$ 115,006

Included in other operating revenue for the year ended December 31, 2007 is interest income of $3,839 (2006 - $3,432) earned on short-term investments.

Short-term investments are recorded at market value.

3. Capital Assets

	2007		2006	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Services	**$ 55,008**	**$ 41,282**	$ 51,195	$ 39,422
Distribution lines - overhead	**343,920**	**284,477**	333,088	273,714
Distribution lines - underground	**244,895**	**179,807**	244,330	170,172
Distribution meters	**66,869**	**48,906**	66,869	47,138
Distribution stations	**41,900**	**5,587**	41,900	4,190
Distribution transformers	**275,392**	**178,441**	252,507	169,169
Other capital assets	**64,146**	**41,263**	69,403	38,417
	$ 1,092,130	**$ 779,763**	$ 1,059,292	$ 742,222
Net book value		**$ 312,367**		$ 317,070

4. Regulatory Assets (Liabilities)

Qualifying transition costs are costs incurred related to the preparations required for market opening. In accordance with Ontario Energy Board (OEB) guidelines, expenditures were allowed to be deferred during the period January 1, 2000 to December 31, 2002, which would be capitalized or expensed under Canadian generally accepted accounting principles for unregulated businesses. For the period January 1, 2003 to December 31, 2007, transition costs were increased by OEB-prescribed carrying charges.

The energy market in Ontario opened to competition on May 1, 2002. Since May 1, 2002, the difference between the cost of power based on time-of-use rates and amounts billed to non-time-of-use customers charged at an average rate are recorded in settlement variance accounts as directed by the OEB. These variance accounts ensure that a utility's gross profit is limited to distribution revenue and service charges.

The regulatory assets recovery account (RARA) includes regulatory asset balances the OEB has approved for recovery. This approved balance will be recovered over a period ending March 31, 2008. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges.

	2007	2006
Regulatory assets (liabilities)		
Settlement variances	**$ (35,569)**	$ (21,842)
Regulatory assets recovery account	**43,471**	102,747
	7,902	80,905
Regulatory liabilities - low voltage	**(48,222)**	(89,130)
	(40,320)	(8,225)
Current portion of regulatory liability	**(23,298)**	(40,909)
Net regulatory assets	**$ (17,022)**	$ 32,684

5. Income Taxes

The provision for income taxes differs from the result which would be obtained by applying the combined Canadian Federal and Provincial Statutory income tax rates to income before income taxes. This difference results from the following items:

	2007	2006
Loss before income taxes	**$ (20,091)**	$ (17,846)
Statutory income tax rate	**18.62** %	18.62 %
Expected income tax recovery	**(3,741)**	(3,323)
Increase (decrease) in taxes resulting from:		
Non-capital losses carried forward	**1,903**	1,791
Amortization in excess of capital cost allowance	**1,838**	1,532
Income tax expense	**$ -**	$ -

As of December 31, 2007, the company has non-capital losses of approximately $44,938 which are available to reduce taxable income in future years. If unused, these losses will expire as follows:

2015	$ 25,098
2026	9,620
2027	10,220
	$ 44,938

6. Share Capital

The authorized common share capital of the company is an unlimited number of shares.

The authorized preference share capital of the company is an unlimited number of preference shares.

The issued share capital is as follows:

		2007	2006
100	Common shares	**$ 100**	$ 100

7. Public Liability Insurance

The company is a member of The Electrical Distributors Association Reciprocal Insurance Exchange which is a pooling of the public liability insurance risks of many of the municipal utilities in Ontario. All members of the pool are subject to assessment for losses experienced by the pool for the years in which they are members on a pro-rata basis based on the total of their respective service revenues.

It is anticipated that, should such an assessment occur, it would be funded over a period of up to five years. To December 31, 2007, no assessments have been made with respect to 2007 or prior years.

8. Future Income Taxes

Future income taxes have not been recognized in these financial statements. Section 3465 of the CICA handbook does not require rate regulated enterprises to recognize future income taxes if future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. The estimated future income tax liability that has not been recognized as at December 31, 2007 is $31,000 (2006 - $29,000).

9. Statement of Cash Flows

	2007	2006
Interest paid	**$ -**	$ 7,247

10. Related Party Transactions

The Township of East Luther Grand Valley is the sole shareholder of the company. The company provides water and sewage billing and collection services to the customers of the Township as well as supplying streetlighting energy and streetlighting maintenance services to the Township.

The following table summarizes the company's related party transactions for the year:

	2007	2006
Revenue		
Sales to parent company	**$ 12,210**	$ 7,435

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

Included in accounts payable at December 31, 2007 is $Nil (2006 - $27,100) payable to the Township.

Included in accounts receivable at December 31, 2007 is $11,778 (2006 - $8,881) receivable from the Township.

11. Contingencies

A class action is seeking $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment charges from customers that were in excess of the interest limit stipulated in 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 since the parties were awaiting the outcome of 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. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the 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.

It is not possible at this time to quantify the effect, if any, of this action on the financial statements of the company.

12. Subsequent Event

The company entered into an agreement on October 9, 2007 to merge with Orangeville Hydro Limited for the purpose of providing electricity distribution services in the Towns of Grand Valley and Orangeville as a single corporate entity. The merger is anticipated to occur in 2008 pending approval by the Ontario Energy Board.

13. Contractual Obligations

The company has a letter of credit of $53,557 issued in favour of the Independent Electricity System Operator (IESO). No amounts have been drawn as at December 31, 2007.

Orangeville Hydro Limited

Financial Statements
For the year ended December 31, 2008

Orangeville Hydro Limited
Financial Statements
For the year ended December 31, 2008

Contents

Auditors' Report

To the Shareholder of
Orangeville Hydro Limited

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

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company 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.

BDO Dunwoody LLP

Chartered Accountants, Licensed Public Accountants

Orangeville, Ontario
March 2, 2009

Orangeville Hydro Limited
Balance Sheet

December 31	2008	2007
Assets		
Current		
Cash (note 1)	**$ 1,622,746**	$ 1,315,135
Accounts receivable (note 13)	**2,851,736**	2,727,540
Accrued unbilled revenue	**1,628,805**	1,696,635
Payments in lieu of income taxes receivable	**146,604**	143,645
Other current assets	**113,072**	204,397
	6,362,963	6,087,352
Due from related party (note 2)	**65,000**	-
Capital assets (note 3)	**13,459,387**	13,257,365
	$ 19,887,350	$ 19,344,717
Liabilities and Shareholder's Equity		
Current		
Accounts payable and accrued liabilities (note 13)	**$ 3,226,498**	$ 2,986,657
Current portion of consumer deposits	**25,000**	25,000
Current portion of long-term debt (note 4)	**196,741**	185,981
Current portion of regulatory liabilities (note 5)	**-**	34,894
Other current liabilities	**181,137**	202,705
	3,629,376	3,435,237
Long-term debt (note 4)	**6,046,799**	6,243,417
Regulatory liabilities (note 5)	**1,255,409**	1,150,666
Post-employment benefits (note 6)	**188,898**	152,331
Consumer deposits	**524,262**	487,812
	11,644,744	11,469,463
Contingency (note 7)		
Shareholder's equity		
Share capital (note 8)	**7,815,535**	7,815,535
Retained earnings (page 4)	**427,071**	59,719
	8,242,606	7,875,254
	$ 19,887,350	$ 19,344,717

On behalf of the Board:

__________________ Director __________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Orangeville Hydro Limited
Statement of Operations and Retained Earnings

For the year ended December 31	2008	2007
Service revenue	**$ 21,670,196**	$ 22,119,800
Cost of power	**17,524,426**	18,006,331
Gross margin on service revenue	**4,145,770**	4,113,469
Other operating revenue	**447,700**	556,052
Gross margin	**4,593,470**	4,669,521
Operating and maintenance expenses		
Distribution	**765,956**	682,534
Billing and collection	**437,086**	418,609
General and administrative	**1,002,821**	988,583
Amortization	**927,631**	929,960
Financial	**409,882**	489,483
	3,543,376	3,509,169
Income before payments in lieu of income taxes	**1,050,094**	1,160,352
Payments in lieu of income taxes (note 9)	**406,026**	513,187
Net income for the year	**644,068**	647,165
Retained earnings, beginning of year	**59,719**	693,115
Dividends	**(276,716)**	(1,280,561)
Retained earnings, end of year	**$ 427,071**	$ 59,719

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Orangeville Hydro Limited
Statement of Cash Flows

For the year ended December 31	2008	2007
Cash provided by (used in)		
Operating activities		
Net income	**$ 644,068**	$ 647,165
Items not involving cash		
Amortization of capital assets	**1,005,961**	1,042,416
Loss (gain) on disposal of capital assets	**3,647**	(5,565)
Increase in post-employment benefits	**36,567**	23,710
	1,690,243	1,707,726
Changes in non-cash working capital balances		
Accounts receivable	**(124,196)**	99,689
Accrued unbilled revenue	**67,830**	(48,019)
Payments in lieu of income taxes receivable	**(2,959)**	(143,645)
Other current assets	**91,325**	(85,047)
Accounts payable and accrued liabilities	**239,841**	164,554
Payments in lieu of income taxes payable	**-**	(14,963)
Current portion of regulatory liabilities	**(34,894)**	(46,370)
Other current liabilities	**(21,568)**	25,060
	215,379	(48,741)
Net change in non-current balance sheet items	**141,193**	(59,214)
	2,046,815	1,599,771
Investing activities		
Purchase of capital assets	**(1,466,569)**	(1,449,064)
Proceeds on sale of capital assets	**694**	5,940
Advance to related party	**(65,000)**	-
	(1,530,875)	(1,443,124)
Financing activities		
Advance of long-term debt	**-**	6,500,000
Repayment of long-term debt	**(185,858)**	(7,870,602)
Dividends	**(276,716)**	(1,280,561)
Capital contributions received	**254,245**	534,860
	(208,329)	(2,116,303)
Increase (decrease) in cash during the year	**307,611**	(1,959,656)
Cash, beginning of year	**1,315,135**	3,274,791
Cash, end of year	**$ 1,622,746**	$ 1,315,135

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Orangeville Hydro Limited
Summary of Significant Accounting Policies

December 31, 2008

Basis of Presentation

The financial statements have been prepared in accordance with accounting principles for municipal electrical utilities in Ontario as required by the Ontario Energy Board under authority of Section 57, 70(2) and 78 of the Ontario Energy Board Act, 1998 and reflect the policies as set forth in the "Accounting Procedures Handbook." All principles employed are in accordance with Canadian generally accepted accounting principles.

Nature of Business

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity. The Distributor is licensed by the Ontario Energy Board (OEB) to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act. The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

Use of Estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

On initial recognition, all financial instruments that meet the definition of a financial asset or financial liability are recorded at fair value, unless fair value cannot be reliably determined. Subsequent measurement depends on whether the financial instrument has been classified as “held-for-trading”, “available-for-sale”, “held-to-maturity”, “loans and receivables” or “other financial liabilities”. The company has elected the following balance sheet classifications with respect to its financial assets and financial liabilities.

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

Accounts receivable, accrued unbilled revenue and due from related party are classified as “loans and receivables” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent

Financial Instruments (continued)

measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts of accounts receivable and accrued unbilled revenue approximate their fair value due to their relatively short periods to maturity. The carrying amount of due to related party approximates fair value since the terms and conditions are comparable to current market conditions.

Accounts payable and accrued liabilities are classified as “other financial liabilities” and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amount of these instruments approximate their fair value due to their relatively short periods to maturity.

Long-term debt is classified as “other financial liabilities” and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amount of long-term debt approximates fair value since the terms and conditions are comparable to current market conditions.

Capital Assets

Capital assets are stated at cost less accumulated amortization. Cost is net of related investment tax credits and government grants. Amortization based on the estimated useful life of the asset is calculated using the straight-line method, with half a year's amortization in the year of acquisition, over the following number of years:

Buildings	50 years
Computer equipment	5 years
Computer software	5 years
Distribution stations	30 years
Distribution system	25 years
Land rights	25 years
Meters	25 years
Office equipment	10 years
Rolling stock	5 - 8 years
Sentinel lights	10 years
Stores equipment	10 years
Tools and equipment	10 years
Transformers	25 years

Spare and replacement parts includes assets not currently in use, which are not amortized.

Corporate Income Taxes	The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered by the customers of the company at that time.
Consumer Deposits	Consumer deposits are cash collections from customers to guarantee the payment of energy bills. The consumer deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.
Regulatory Assets/Liabilities	Regulatory assets/liabilities represent costs/receipts that have been deferred according to OEB regulatory guidelines. Regulatory assets/liabilities are reflected on the balance sheet until the manner and timing of disposition is determined by the OEB.
Post Employment Benefits	The company accrues its obligations under employee benefit plans and the related costs net of plan assets, if any. The company has adopted the following policy: The cost of retirement benefits earned by employees is actuarially determined using the projected unit method pro-rated on service and management's best estimate of retirement ages of employees and expected health care costs. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gain (loss) over 10% of the benefit plan obligation is amortized over the average remaining service period of active employees.
Revenue	Revenue is recognized in the financial statements on the accrual basis when the energy is supplied to the users, whether billed or unbilled.

Changes in Accounting Principles

Effective January 1, 2008, the company adopted the new requirements of the Canadian Institute of Chartered Accountants (CICA) in the following areas.

Capital Disclosures

CICA Handbook Section 1535, Capital Disclosures, requires disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity manages as capital, whether during the period the entity complied with any externally imposed capital requirements and, if the company has not complied, the consequences of such non-compliance. These disclosures have been described in note 12.

Financial Instruments - Disclosures and Presentation

CICA Handbook Sections 3862, Financial Instruments - Disclosures and 3863, Financial Instruments - Presentation, requires increased disclosures regarding the risks associated with financial instruments such as credit, liquidity and market risks and the techniques used to identify, monitor and manage these risks. Section 3863 carries forward unchanged the presentation requirements of Section 3861. These disclosures have been described in note 13.

Inventories

CICA Handbook Section 3031, Inventories, replaces Section 3030. This new standard provides more extensive guidance on the determination of cost, including allocation of overheads; requires inventories to be measured at the lower of cost and net realizable value; provides more restrictive guidance on the cost methodologies used; and, restricts the classification of spare and replacement parts as inventory. Additional disclosure requirements are prescribed including disclosures relating to the accounting policies adopted in measuring inventories, the carrying amount of inventories, the amount of inventories recognized as an expense during the period, the amount of write downs during the period and the amount of any reversal of write downs that is recognized as a reduction of expenses.

Changes in Accounting Principles (continued)

In accordance with the new requirements, the company has retrospectively reclassified all spare and replacement parts from inventory to capital assets. As at December 31, 2008, $296,963 was reclassified out of inventory and into capital assets (2007 - $323,303).

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

Future Income Taxes

CICA Handbook Section 3465, Income Taxes, has been amended to require rate regulated entities to recognize future income tax liabilities and assets, as well as a regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to future customers. The amendments are effective for fiscal years beginning on or after January 1, 2009. The company is currently assessing the impact of this standard.

International Financial Reporting Standards

On February 13, 2008, the Accounting Standards Board (ACSB) confirmed that publicly accountable entities will be required to adopt IFRS in place of Canadian GAAP for reporting purposes for fiscal years beginning on or after January 1, 2011. The company is currently developing an implementation plan for the adoption of IFRS. At this time, the impact on the company's financial statements is not reasonably determinable or estimable.

1. Cash

The company's bank accounts are held at one chartered bank. Interest earned on cash balances for the year ended December 31, 2008 was $69,831 (2007 - $154,660) and is included in other operating revenue on the income statement.

2. Related Party Transactions

The Town of Orangeville is the sole shareholder of the company. The company provides water and sewage billing and collection services to the customers of the Town as well as supplying streetlighting energy and streetlighting maintenance services to the Town.

The following table summarizes the company's related party transactions for the year:

	2008	2007
Revenue		
Sales to parent company	**$ 425,848**	$ 367,109

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

Included in accounts payable at December 31, 2008 is $579,378 (2007 - $556,042) payable to the Town.

Included in accounts receivable at December 31, 2008 is $73,224 (2007 - $71,756) receivable from the Town.

At the end of the year, the amount due from related parties is as follows:

	2008	2007
Wholly-owned subsidiary of parent company	**$ 65,000**	$ -

This balance represents an operating loan and bears interest at a rate of 6.0% per annum and is due April 30, 2013.

3. Capital Assets

	2008		2007	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Land	**$ 212,281**	**$ 13,542**	$ 212,281	$ 12,190
Buildings	**2,727,221**	**772,025**	2,620,518	727,581
Services	**2,174,541**	**1,314,344**	2,144,587	1,222,536
Distribution lines - overhead	**7,298,905**	**4,128,266**	7,079,361	3,881,985
Distribution lines - underground	**6,830,133**	**3,138,243**	6,391,113	2,887,107
Distribution meters	**1,736,865**	**940,278**	1,701,317	881,241
Distribution stations	**860,992**	**540,541**	848,022	517,791
Distribution transformers	**7,416,203**	**3,278,774**	6,849,283	3,012,218
Other capital assets	**1,937,271**	**1,512,204**	1,910,373	1,422,246
Spare and replacement parts	**296,963**	**-**	323,303	-
	31,491,375	**15,638,217**	30,080,158	14,564,895
Contributions and grants	**(3,086,415)**	**(692,644)**	(2,832,170)	(574,272)
	$ 28,404,960	**$ 14,945,573**	$ 27,247,988	$ 13,990,623
Net book value		**$ 13,459,387**		$ 13,257,365

4. Long-term Debt

	2008	2007
Term loan payable - TD Bank, 5.59%, due 2017, repayable in monthly payments of $45,048 principal and interest	**$ 6,243,540**	$ 6,429,398
Less amounts due within one year included in current liabilities	**196,741**	185,981
	$ 6,046,799	$ 6,243,417

The agreement with respect to the TD Bank term loan contains certain covenants regarding (i) leverage, (ii) liquidity, (iii) restrictions on business activities, (iv) restrictions on distributions, (v) change in ownership, (vi) mergers, acquisitions or change in line of business and (vii) limitations on additional debt and encumbrance of assets.

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

2009	$ 196,741
2010	206,912
2011	218,779
2012	230,432
2013	244,543
Thereafter	5,146,133
	$ 6,243,540

The interest on long-term debt during the year amounted to $354,715 and is included in financial expense.

Other credit facilities includes an operating facility of up to $2,500,000, of which $1,667,771 was available as at December 31, 2008 (2007 - $1,667,771).

5. Regulatory Assets and Liabilities

	2008	2007
Regulatory assets (liabilities)		
Qualifying transition costs	**$ (12,260)**	$ (11,746)
Settlement variances	**(1,199,561)**	(901,530)
Regulatory assets recovery account	**(1,073)**	(167,038)
Low voltage asset (liability)	**13,319**	(67,945)
Smart meters	**(55,834)**	(37,301)
	(1,255,409)	(1,185,560)
Current portion of regulatory liabilities	**-**	(34,894)
Net regulatory liabilities	**$ (1,255,409)**	$ (1,150,666)

Qualifying transition costs are costs incurred related to the preparations required for market opening. In accordance with Ontario Energy Board (OEB) guidelines, expenditures were allowed to be deferred during the period January 1, 2000 to December 31, 2002, which would be capitalized or expensed under Canadian generally accepted accounting principles for unregulated businesses. For the period January 1, 2003 to December 31, 2008, transition costs were increased by OEB-prescribed carrying charges.

The energy market in Ontario opened to competition on May 1, 2002. Since May 1, 2002, the difference between the cost of power based on time-of-use rates and amounts billed to non-time-of-use customers charged at an average rate are recorded in settlement variance accounts as directed by the OEB. These variance accounts ensure that a utility's gross profit is limited to distribution revenue and service charges.

The regulatory assets recovery account (RARA) includes regulatory asset balances the OEB has approved for recovery. This approved balance was recovered over a period ending March 31, 2008, with a difference of $1,073 to be settled based on future direction from the OEB. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges.

Beginning May 1, 2006, the OEB has allowed the company to defer the revenues approved by the OEB for smart meters and the related capital costs incurred by the company. Accordingly, the company has deferred these amounts in accordance with the criteria set out by the OEB.

6. Pension Agreement and Post Employment Benefits

(a) Pension Agreement

The company makes contributions to the Ontario Municipal Employees Retirement Fund (OMERS), which is a multi-employer plan, on behalf of members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The amount contributed to OMERS for the year ending December 31, 2008 was $99,037 (2007 - $86,765) for current service. There is no liability for past service.

(b) Post Employment Benefits

The company provides certain non-pension post-employment benefits consisting of extended health and other benefits. The cost of providing pension and other post-retirement benefits is actuarially determined and charged to operations using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, terminations, retirement ages of plan members and expected health care costs. The pension expense for the year includes adjustments for plan amendments, experience gains and losses and changes in assumptions that are being amortized on a straight-line basis over the expected average remaining service lives of the plan members. Any differences between the cumulative amounts expensed and the funding contributions are reflected as either an asset or a liability.

The latest actuarial valuation of the benefit plan, as of December 31, 2007, estimated the post employment benefit liability to be $160,465.

	2008	2007
Accrued benefit obligation	**$ 315,467**	$ 244,600
Less unamortized past service costs	**126,569**	92,269
Benefit plan obligation	**$ 188,898**	$ 152,331
Benefit plan expense	**$ 49,035**	$ 36,595
Less benefit plan payments	**12,468**	12,885
Net plan expense	**$ 36,567**	$ 23,710

7. Contingency

A class action is seeking $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities (LDCs) who received late payment charges from customers that were in excess of the interest limit stipulated in 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 since the parties were awaiting the outcome of 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. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the 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.

It is not possible at this time to quantify the effect, if any, of this action on the financial statements of the company.

8. Share Capital

The authorized common share capital of the company is an unlimited number of shares.

The issued share capital is as follows:

		2008	2007
100	Common shares	**$ 7,815,535**	$ 7,815,535

9. Income Taxes

The provision for income taxes differs from the result which would be obtained by applying the combined Canadian Federal and Provincial Statutory income tax rates to income before income taxes. This difference results from the following items:

	2008	2007
Income before income taxes	**$ 1,050,094**	$ 1,160,352
Statutory income tax rate	**33.50** %	36.12 %
Expected income tax expense	**351,781**	419,119
Increase (decrease) in taxes resulting from:		
Permanent differences	**(7,706)**	(5,385)
Amortization in excess of capital cost allowance	**54,177**	72,099
Post-employment expenses in excess of payments	**12,250**	8,564
Pre-market opening energy variances	**9,264**	39,955
Other	**-**	(29)
Small business tax rate reduction	**(10,495)**	-
Prior year amendments	**(3,245)**	(21,136)
Income tax expense	**$ 406,026**	$ 513,187

10. Future Income Taxes

Future income taxes have not been recognized in these financial statements. Section 3465 of the CICA handbook does not require rate regulated enterprises to recognize future income taxes if future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. The estimated future income tax asset that has not been recognized as at December 31, 2008 is $540,000 (2007 - $470,000).

11. Statement of Cash Flows

	2008	2007
Interest paid	**$ 354,517**	$ 422,189
Payments in lieu of income taxes	**$ 560,000**	$ 683,038

12. Capital Disclosures

The company's objectives when managing its capital are to:

- maintain a financial position suitable for supporting the company's operations and growth strategies;
- provide an adequate return to its shareholder;
- comply with covenants related to its credit facilities; and
- align its capital structure for regulated activities with debt to equity structure recommended by the OEB, which is 60% debt and 40% equity by 2010.

The company defines capital as the aggregate of shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2007. As at December 31, 2008, shareholder's equity amounts to $8,243,848 (2007 - $7,875,254) and long-term debt amounts to $6,243,540 (2007 - $6,429,398). The company's capital structure as at December 31, 2008 is 43% debt and 57% equity (2007 - 45% debt and 55% equity). There have been no changes in the company's overall capital management strategy during the year.

The company has externally imposed capital requirements in the form of credit facility agreements that contain various covenants (note 4). The company's credit facility limits the debt to capitalization ratio to 60.0%. As at December 31, 2008, the debt to capitalization ratio was 31.0% (2007 - 32.0%). The company was in compliance with all credit facility agreement covenants as at December 31, 2008 (and 2007).

13. Financial Instruments Risk Factors

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

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

Credit risk

Financial instruments are exposed to credit risk due to the risk of a counter-party defaulting on its obligations. The company’s maximum exposure to credit risk is equal to the carrying value of its financial assets. The company’s objective is to maximize credit collection and minimize bad debt expense. Credit risk is managed by monitoring and limiting exposure to credit risk on a continuous basis.

The credit risk associated with accounts receivable is the collection of amounts due from customers. The majority of the company's customers are residential customers. The company has procedures in place to ensure timely follow up on overdue amounts and to ensure additional credit is not extended to customers with certain arrears. The company collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2008, the company held security deposits in the amount of $549,262 (2007 - $512,812). The company also has insurance that provides $0.12 on every dollar of bad debt.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts based on the financial condition of counter-parties and by applying to total accounts receivable a percentage based on past experience. The amount of the related impairment loss is recognized in the income statement. Subsequent recoveries of receivables previously provisioned are credited to the income statement.

Credit risk associated with accounts receivable is as follows:

	2008	2007
Total accounts receivable	**$ 2,863,836**	$ 2,747,540
Allowance for doubtful accounts	**(12,100)**	(20,000)
Total accounts receivable, net	**$ 2,851,736**	$ 2,727,540

13. Financial Instruments Risk Factors (continued)

Accounts receivable outstanding for:		
Not more than 30 days	**$ 2,654,141**	$ 2,534,250
More than 30 days	**209,695**	213,290
Allowance for doubtful accounts	**(12,100)**	(20,000)
Total accounts receivable, net	**$ 2,851,736**	$ 2,727,540

At December 31, 2008, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties.

Liquidity risk

The following liquidity risks are associated with financial instruments: accounts payable and accrued liabilities are due within one year; and long-term debt commitments (note 4). The company's objective is to ensure it has access to sufficient funds to meet cash flow commitments related to financial instruments. Liquidity risk is managed by monitoring cash balances, maintaining a portion of assets in liquid securities and having access to credit facilities.

Interest rate risk

The company is exposed to interest rate risk on its long-term debt. The company's objective is to minimize net interest expense. Interest rate risk is managed by entering into long-term fixed-rate debt.

14. Public Liability Insurance

The company is a member of The Electrical Distributors Association Reciprocal Insurance Exchange which is a pooling of the public liability insurance risks of many of the municipal utilities in Ontario. All members of the pool are subject to assessment for losses experienced by the pool for the years in which they are members on a pro-rata basis based on the total of their respective service revenues.

It is anticipated that, should such an assessment occur, it would be funded over a period of up to five years. To December 31, 2008, no assessments have been made with respect to 2008 or prior years.

15. Subdivision Agreements

As part of various subdivision agreements, the company has received letters of credit to cover developers' responsibilities in completing the projects. Letters of credit held by the company at December 31, 2008 amount to $653,457 (2007 - $414,448).

16. Subsequent Event

The company entered into an agreement on December 3, 2007 to merge with Grand Valley Energy Inc. for the purpose of providing electricity distribution services in the Towns of Orangeville and Grand Valley as a single corporate entity. The merger was approved by the Ontario Energy Board during 2008 and occurred on January 1, 2009.

17. Contractual Obligations

The company has a letter of credit of $832,229 issued in favour of the Independent Electricity System Operator (IESO). No amounts have been drawn as at December 31, 2008.

18. Dividends

Subject to applicable law, shareholder direction provided that the company would pay dividends to the Town of Orangeville in December of each year in the amount of 50% of the company's projected annual net income. Additional dividends may be applicable as long as the financing covenants are met and regulatory compliance is maintained. During 2008, the board of directors of the company declared and paid dividends totaling $276,716 to the Town (2007 - $1,280,561).

Covenants in the company's financing agreements state that no dividends, withdrawals, bonuses, advances to shareholders, management or affiliates are permitted that would place any bank credit conditions in default.

Grand Valley Energy Inc.

Financial Statements
For the year ended December 31, 2008

Grand Valley Energy Inc.
Financial Statements
For the year ended December 31, 2008

Contents

Auditors' Report

To the Shareholder of
Grand Valley Energy Inc.

We have audited the balance sheet of Grand Valley Energy Inc. as at December 31, 2008 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company 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.

BDO Dunwoody LLP

Chartered Accountants, Licensed Public Accountants

Orangeville, Ontario
March 2, 2009

Grand Valley Energy Inc.
Balance Sheet

December 31		2008		2007
Assets				
Current				
Cash (note 1)	$	**168,663**	$	88,862
Short-term investments (note 2)		**69,830**		67,428
Accounts receivable (note 11)		**152,960**		153,943
Prepaid expenses		**-**		3,341
Accrued unbilled revenue		**49,591**		59,025
Other current assets		**10,762**		3,264
		451,806		375,863
Capital assets (note 3)		**345,763**		312,367
	$	**797,569**	$	688,230
Liabilities and Shareholder's Equity				
Current				
Accounts payable and accrued liabilities (note 11)	$	**269,322**	$	137,639
Current portion of consumer deposits		**3,000**		3,000
Current portion of regulatory liabilities (note 4)		**7,314**		23,298
Other current liabilities		**9,009**		9,004
		288,645		172,941
Regulatory liabilities (note 4)		**16,758**		17,022
Consumer deposits		**16,988**		14,810
		322,391		204,773
Contingencies (note 6)				
Shareholder's equity				
Share capital (note 7)		**100**		100
Contributed surplus		**436,871**		436,871
Retained earnings (page 4)		**38,207**		46,486
		475,178		483,457
	$	**797,569**	$	688,230

On behalf of the Board:

________________ Director ________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Grand Valley Energy Inc.
Statement of Operations and Retained Earnings

For the year ended December 31	2008	2007
Service revenue	**$ 927,107**	$ 952,481
Cost of power	**690,812**	725,993
Gross margin on service revenue	**236,295**	226,488
Other operating revenue	**22,162**	29,434
Gross margin	**258,457**	255,922
Operating and maintenance expenses		
Distribution	**32,409**	34,092
Billing and collection	**64,628**	64,979
General and administrative	**115,796**	133,070
Amortization	**42,794**	42,798
Financial	**1,109**	1,075
	256,736	276,014
Net income (loss) for the year	**1,721**	(20,092)
Retained earnings, beginning of year	**46,486**	121,578
Dividends	**(10,000)**	(55,000)
Retained earnings, end of year	**$ 38,207**	$ 46,486

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Grand Valley Energy Inc.
Statement of Cash Flows

For the year ended December 31	2008	2007
Cash provided by (used in)		
Operating activities		
Net income (loss)	**$ 1,721**	$ (20,092)
Items not involving cash		
Amortization of capital assets	**42,794**	42,798
	44,515	22,706
Changes in non-cash working capital balances		
Accounts receivable	**983**	20,861
Inventory	**-**	905
Prepaid expenses	**3,341**	2,832
Accrued unbilled revenue	**9,434**	(1,795)
Other current assets	**(7,498)**	2,570
Accounts payable and accrued liabilities	**131,683**	(16,371)
Payments in lieu of income taxes recoverable	**-**	5,988
Current portion of regulatory liabilities	**(15,984)**	(17,611)
Other current liabilities	**5**	1,694
	121,964	(927)
Net change in non-current balance sheet items	**1,914**	53,816
	168,393	75,595
Investing activities		
Purchase of capital assets	**(76,190)**	(38,095)
Purchase of short-term investments	**(2,402)**	-
Net proceeds on sale of short-term investments	**-**	47,578
	(78,592)	9,483
Financing activities		
Dividends	**(10,000)**	(55,000)
Increase in cash during the year	**79,801**	30,078
Cash, beginning of year	**88,862**	58,784
Cash, end of year	**$ 168,663**	$ 88,862

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Basis of Presentation

The financial statements have been prepared in accordance with accounting principles for municipal electrical utilities in Ontario as required by the Ontario Energy Board under authority of Section 57, 70(2) and 78 of the Ontario Energy Board Act, 1998 and reflect the policies as set forth in the "Accounting Procedures Handbook." All principles employed are in accordance with Canadian generally accepted accounting principles.

Nature of Business

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity. The Distributor is licensed by the Ontario Energy Board (OEB) to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act. The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

Use of Estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

Financial Instruments

On initial recognition, all financial instruments that meet the definition of a financial asset or financial liability are recorded at fair value, unless fair value cannot be reliably determined. Subsequent measurement depends on whether the financial instrument has been classified as “held-for-trading”, “available-for-sale”, “held-to-maturity”, “loans and receivables” or “other financial liabilities”. The company has elected the following balance sheet classifications with respect to its financial assets and financial liabilities.

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

Financial Instruments (continued)

Short-term investments are classified as “held-to-maturity” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. The carrying amount of short-term investments approximates fair value due to its relatively short period to maturity.

Accounts receivable and accrued unbilled revenue are classified as “loans and receivables” and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts of these instruments approximate their fair value due to their relatively short periods to maturity.

Accounts payable and accrued liabilities are classified as “other financial liabilities” and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amount of these instruments approximate their fair value due to their relatively short periods to maturity.

Corporate Income Taxes

The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered by the customers of the company at that time.

Capital Assets

Capital assets are stated at cost less accumulated amortization. Cost is net of related investment tax credits and government grants. Amortization based on the estimated useful life of the asset is calculated using the straight-line method, with half a year's amortization in the year of acquisition, over the following number of years:

Computer equipment	5 years
Computer software	5 years
Distribution stations	30 years
Distribution system	25 years
Meters	25 years
Office equipment	10 years
Rolling stock	5 - 8 years
Sentinel lights	10 years
Stores equipment	10 years
Tools and equipment	10 years
Transformers	25 years

Consumer Deposits

Consumer deposits are cash collections from customers to guarantee the payment of energy bills. The consumer deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

Regulatory Assets/Liabilities

Regulatory assets/liabilities represent costs/receipts that have been deferred according to OEB regulatory guidelines. Regulatory assets/liabilities are reflected on the balance sheet until the manner and timing of disposition is determined by the OEB.

Revenue

Revenue is recognized in the financial statements on the accrual basis when the energy is supplied to the users, whether billed or unbilled.

Changes in Accounting Principles

Effective January 1, 2008, the company has adopted the new requirements of the Canadian Institute of Chartered Accountants (CICA) in the following areas.

Capital Disclosures

CICA Handbook Section 1535, Capital Disclosures, requires disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity manages as capital, whether during the period the entity complied with any externally imposed capital requirements and, if the company has not complied, the consequences of such non-compliance. These disclosures have been described in note 10.

Financial Instruments - Disclosures and Presentation

CICA Handbook Sections 3862, Financial Instruments - Disclosures and 3863, Financial Instruments - Presentation, require increased disclosures regarding the risks associated with financial instruments such as credit, liquidity and market risks and the techniques used to identify, monitor and manage these risks. Section 3863 carries forward unchanged the presentation requirements of Section 3861. These disclosures have been described in note 11.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

Future Income Taxes

CICA Handbook Section 3465, Income Taxes, has been amended to require rate regulated entities to recognize future income tax liabilities and assets, as well as a regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to future customers. The amendments are effective for fiscal years beginning on or after January 1, 2009. The company is currently assessing the impact of this standard.

New Accounting Pronouncements (continued)

International Financial Reporting Standards

On February 13, 2008, the Accounting Standards Board (ACSB) confirmed that publicly accountable entities will be required to adopt IFRS in place of Canadian GAAP for reporting purposes for fiscal years beginning on or after January 1, 2011. The company is currently developing an implementation plan for the adoption of IFRS. At this time, the impact on the company's financial statements is not reasonably determinable or estimable.

1. Cash

The company's bank accounts are held at one chartered bank.

2. Short-term Investments

	2008	2007
Equitable Trust, five year annual GIC, due October 2010, 3.86%	**$ 69,830**	$ 67,428

Included in other operating revenue for the year ended December 31, 2008 is interest income of $2,402 (2007 - $3,839) earned on short-term investments.

Short-term investments are recorded at market value.

3. Capital Assets

	2008		2007	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Services	**$ 56,489**	**$ 43,148**	$ 55,008	$ 41,282
Distribution lines - overhead	**398,537**	**296,333**	343,920	284,477
Distribution lines - underground	**244,895**	**189,023**	244,895	179,807
Distribution meters	**67,051**	**50,678**	66,869	48,906
Distribution stations	**41,900**	**6,983**	41,900	5,587
Distribution transformers	**295,300**	**188,112**	275,392	178,441
Other capital assets	**63,868**	**48,000**	64,146	41,263
	$ 1,168,040	**$ 822,277**	$ 1,092,130	$ 779,763
Net book value		**$ 345,763**		$ 312,367

4. Regulatory Assets and Liabilities

	2008	2007
Regulatory assets (liabilities)		
Settlement variances	**$ (27,516)**	$ (31,572)
Regulatory assets recovery account	**17,119**	43,471
Low voltage liability	**(7,314)**	(48,222)
Smart meters	**(6,361)**	(3,997)
	(24,072)	(40,320)
Current portion of regulatory liabilities	**(7,314)**	(23,298)
Net regulatory liabilities	**$ (16,758)**	$ (17,022)

The energy market in Ontario opened to competition on May 1, 2002. Since May 1, 2002, the difference between the cost of power based on time-of-use rates and amounts billed to non-time-of-use customers charged at an average rate are recorded in settlement variance accounts as directed by the OEB. These variance accounts ensure that a utility's gross profit is limited to distribution revenue and service charges.

The regulatory assets recovery account (RARA) includes regulatory asset balances the OEB has approved for recovery. This approved balance was recovered over a period ending March 31, 2008, with a difference of $17,119 to be settled based on future direction from the OEB. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges.

Beginning May 1, 2006, the OEB has allowed the company to defer the revenues approved by the OEB for smart meters and the related capital costs incurred by the company. Accordingly, the company has deferred these amounts in accordance with the criteria set out by the OEB.

5. Related Party Transactions

The Township of East Luther Grand Valley is the sole shareholder of the company. The company provides water and sewage billing and collection services to the customers of the Township as well as supplying streetlighting energy and streetlighting maintenance services to the Township.

The following table summarizes the company's related party transactions for the year:

	2008	2007
Revenue		
Sales to parent company	**$ 14,074**	$ 12,210

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product.

Included in accounts payable at December 31, 2008 is $26,137 (2007 - $Nil) payable to the Township.

Included in accounts receivable at December 31, 2008 is $12,418 (2007 - $11,778) receivable from the Township.

6. Contingencies

A class action is seeking $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment charges from customers that were in excess of the interest limit stipulated in 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 since the parties were awaiting the outcome of 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. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the 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.

It is not possible at this time to quantify the effect, if any, of this action on the financial statements of the company.

7. Share Capital

The authorized common share capital of the company is an unlimited number of shares.

The authorized preference share capital of the company is an unlimited number of preference shares.

The issued share capital is as follows:

		2008	2007
100	Common shares	**$ 100**	$ 100

8. Income Taxes

The provision for income taxes differs from the result which would be obtained by applying the combined Canadian Federal and Provincial Statutory income tax rates to income before income taxes. This difference results from the following items:

	2008	2007
Income (loss) before income taxes	**$ 1,721**	$ (20,092)
Statutory income tax rate	**16.50** %	18.62 %
Expected income tax expense	**284**	(3,741)
Increase (decrease) in taxes resulting from:		
Losses applied to reduce current taxes	**(3,592)**	-
Non-capital losses carried forward	**-**	1,903
Amortization in excess of capital cost allowance	**3,308**	1,838
Income tax expense	**$ -**	$ -

As of December 31, 2008, the company has non-capital losses of approximately $23,168 which are available to reduce taxable income in future years. If unused, these losses will expire as follows:

2015	$ 3,330
2026	9,620
2027	10,218
	$ 23,168

9. Future Income Taxes

Future income taxes have not been recognized in these financial statements. Section 3465 of the CICA handbook does not require rate regulated enterprises to recognize future income taxes if future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. The estimated future income tax liability that has not been recognized as at December 31, 2008 is $31,000 (2007 - $31,000).

10. Capital Disclosures

The company's objectives when managing its capital are to:

- maintain a financial position suitable for supporting the company's operations and growth strategies;
- provide an adequate return to its shareholder; and
- align its capital structure for regulated activities with debt to equity structure recommended by the OEB, which is 60% debt and 40% equity by 2010.

The company defines capital as the aggregate of shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2007. As at December 31, 2008, shareholder's equity amounts to $475,178 (2007 - $483,457) and long-term debt amounts to $Nil (2007 - $Nil). The company's capital structure as at December 31, 2008 is 100% equity (2007 - 100% equity). There have been no changes in the company's overall capital management strategy during the year.

The company has no externally imposed capital requirements.

11. Financial Instruments Risk Factors

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

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

Credit risk

Financial instruments are exposed to credit risk due to the risk of a counter-party defaulting on its obligations. The company's maximum exposure to credit risk is equal to the carrying value of its financial assets. The company's objective is to maximize credit collection and minimize bad debt expense. Credit risk is managed by monitoring and limiting exposure to credit risk on a continuous basis.

11. Financial Instruments Risk Factors (continued)

The credit risk associated with accounts receivable is the collection of amounts due from customers. The majority of the company's customers are residential customers. The company has procedures in place to ensure timely follow up on overdue amounts and to ensure additional credit is not extended to customers with certain arrears. The company collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2008, the company held security deposits in the amount of $19,988 (2007 - $17,810).

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts based on the financial condition of counter-parties and by applying to total accounts receivable a percentage based on past experience. The amount of the related impairment loss is recognized in the income statement. Subsequent recoveries of receivables previously provisioned are credited to the income statement.

Credit risk associated with accounts receivable is as follows:

	2008	2007
Total accounts receivable	**$ 155,860**	$ 163,078
Allowance for doubtful accounts	**(2,900)**	(9,135)
Total accounts receivable, net	**$ 152,960**	$ 153,943

	2008	2007
Accounts receivable outstanding for:		
Not more than 30 days	**$ 130,320**	$ 135,417
More than 30 days	**25,540**	27,661
Allowance for doubtful accounts	**(2,900)**	(9,135)
Total accounts receivable, net	**$ 152,960**	$ 153,943

At December 31, 2008, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties.

Liquidity risk

The following liquidity risks are associated with financial instruments: accounts payable and accrued liabilities are due within one year. The company’s objective is to ensure it has access to sufficient funds to meet cash flow commitments related to financial instruments. Liquidity risk is managed by monitoring cash balances, maintaining a portion of assets in liquid securities and having access to credit facilities.

12. Public Liability Insurance

The company is a member of The Electrical Distributors Association Reciprocal Insurance Exchange which is a pooling of the public liability insurance risks of many of the municipal utilities in Ontario. All members of the pool are subject to assessment for losses experienced by the pool for the years in which they are members on a pro-rata basis based on the total of their respective service revenues.

It is anticipated that, should such an assessment occur, it would be funded over a period of up to five years. To December 31, 2008, no assessments have been made with respect to 2008 or prior years.

13. Subsequent Event

The company entered into an agreement on October 9, 2007 to merge with Orangeville Hydro Limited for the purpose of providing electricity distribution services in the Towns of Grand Valley and Orangeville as a single corporate entity. The merger was approved by the Ontario Energy Board during 2008 and occurred on January 1, 2009.

14. Contractual Obligations

The company has a letter of credit of $53,557 issued in favour of the Independent Electricity System Operator (IESO). No amounts have been drawn as at December 31, 2008.

PRO FORMA FINANCIAL STATEMENTS - 2009 AND 2010:

The OHL Pro Forma Statements for the 2009 Bridge Year and the 2010 Test Year accompany this Schedule as Appendix G and Appendix H respectively.

Orangeville Hydro Limited
EB-2009-0272
Exhibit 1
Tab 3
Schedule 2
Appendix G
Filed: August 28, 2009

APPENDIX G

COPY OF Orangeville Hydro Limited
2009 PRO FORMA STATEMENTS

Orangeville Hydro Limited
Statement of Operations and Retained Earnings

For the year December 31	2009	2008
Revenue	$ 24,285,047	$ 22,590,994
Direct Costs	19,919,438	18,215,238
	4,365,609	4,375,756
Other revenues		
Investment income	44,885	91,451
Gain (Loss) on disposal of capital assets	15,120	(3,647)
Other income	17,257	17,279
Other operating income	364,742	369,613
	4,807,613	4,850,452
Expenses		
Administration and general	1,085,925	1,071,912
Amortization	1,067,259	970,425
Billing and collecting	508,659	501,713
Community relations	12,584	42,551
Distribution	767,067	796,919
Interest	394,716	410,991
Taxes other than income taxes	4,795	4,125
	3,841,004	3,798,636
Net income from operations for the year	966,609	1,051,815
Payments in lieu of income taxes (PILs)	270,368	406,026
Net income for the year	696,241	645,789
Retained earnings, beginning of year	465,281	106,208
Dividends paid	(307,000)	(286,716)
Retained earnings, end of year	$ 854,521	$ 465,281

Orangeville Hydro Limited
EB-2009-0272
Exhibit 1
Tab 3
Schedule 2
Appendix G
Filed: August 28, 2009

Orangeville Hydro Limited
Balance Sheet

December 31		2009		2008
Assets				
Current				
Cash	$	1,953,229	$	1,861,239
Accounts Receivable		3,004,696		3,004,696
Unbilled service revenue		1,678,396		1,678,396
Inventory		296,963		296,963
Other current assets		123,838		123,838
PILs recoverable				
		7,057,123		6,965,132
Capital assets		14,067,176		13,508,184
Regulatory assets		714,514		(1,285,486)
Other assets		65,000		65,000
Total Assets	$	21,903,812	$	19,252,830
Liabilities and Shareholder's Equity				
Current				
Accounts payable and accrued liabilities	$	3,679,960	$	3,679,960
Current PILs payable		-		(146,604)
Current portion of long-term debt		196,741		196,741
Current portion of Customer Deposit		28,000		28,000
		3,904,701		3,758,097
Long-term debt		7,850,799		6,046,799
Long-term customer deposits		541,250		541,250
Other non-current liabilities		-		-
Employee future benefits		213,319		188,898
Other regulatory liabilities		-		-
	$	12,510,069	$	10,535,044
Shareholder's equity				
Share capital		7,815,635		7,815,635
Retained earnings		1,578,108		902,152
	$	9,393,743	$	8,717,786
Total Liabilities and Shareholders Equity	$	21,903,812	$	19,252,830

APPENDIX H

COPY OF Orangeville Hydro Limited 2010 PRO FORMA STATEMENTS

Orangeville Hydro Limited
Statement of Operations and Retained Earnings

For the year December 31	2010	2009
Revenue	$ 24,698,562	$ 24,296,570
Direct Costs	19,666,513	19,919,438
	5,032,050	4,377,133
Other revenues		
Investment income	44,810	44,885
Gain (Loss) on disposal of capital assets	1,600	15,120
Other income	500	17,257
Other operating income	385,142	353,219
	5,464,101	4,807,613
Expenses		
Administration and general	1,283,872	1,085,925
Amortization	1,119,762	1,067,259
Billing and collecting	559,953	508,659
Community relations	28,862	12,584
Distribution	901,369	767,067
Interest	493,788	394,716
Taxes other than income taxes	2,099	4,795
	4,389,705	3,841,004
Net income from operations for the year	1,074,396	966,609
Payments in lieu of income taxes (PILs)	248,138	270,368
Net income for the year	826,258	696,241
Retained earnings, beginning of year	854,521	465,281
Dividends paid	(338,000)	(307,000)
Retained earnings, end of year	$ 1,342,780	$ 854,521

Orangeville Hydro Limited
Balance Sheet

December 31	2010	2009
Assets		
Current		
Cash	$ 1,943,107	$ 1,958,099
Accounts Receivable	3,004,696	3,004,696
Unbilled service revenue	1,678,396	1,678,396
Inventory	296,963	296,963
Other current assets	123,838	123,838
PILs recoverable		
	7,047,001	7,061,993
Capital assets	14,634,951	14,067,176
Regulatory assets	714,514	714,514
Other assets	65,000	65,000
Total Assets	$ 22,461,466	$ 21,908,682
Liabilities and Shareholder's Equity		
Current		
Accounts payable and accrued liabilities	$ 3,679,960	$ 3,679,960
Current PILs payable	-	-
Current portion of long-term debt	196,741	196,741
Current portion of Customer Deposit	28,000	28,000
	3,904,701	3,904,701
Long-term debt	7,612,508	7,850,799
Long-term customer deposits	541,250	541,250
Other non-current liabilities	-	-
Employee future benefits	239,728	213,319
Other regulatory liabilities	-	-
	$ 12,298,187	$ 12,510,069
Shareholder's equity		
Share capital	7,815,635	7,815,635
Retained earnings	2,347,644	1,582,978
	$ 10,163,278	$ 9,398,613
Total Liabilities and Shareholders Equity	$ 22,461,466	$ 21,908,682

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

OHL advises that because the 2008 Audited Financial Statements do not vary from the regulatory financial results filed in this Application, a reconciliation between the financial statements and financial results filed has not been provided. However, as a result of differences between deemed and actual interest expense, non utility revenue and expenses, 50% Gain in Disposal and interest revenue on regulatory assets. The following chart provides a reconciliation for 2010 Pro Forma Statements and the Revenue Deficiency Statements.

DEEMED NET INCOME	**570,284**
PLUS	
50% GAIN ON DISPOSAL	800
NON-UTILITY REVENUE	410,363
NON-UTILITY EXPENSES	(311,683)
INTEREST REVENUE ON REG ASSETS	2,387
DEEMED INTEREST EXPENSE	652,936
ACTUAL INTEREST EXPENSE	493,788
ADD BACK DIFFERENCE	159,147
LESS	
DONATIONS	5,040
NET INCOME PER INCOME STATEMENT	**826,258**

INFORMATION ON AFFILIATES

Orangeville Hydro Services Inc. is a non-active affiliate of Orangeville Hydro Limited. It is wholly owned by the Town of Orangeville.

Green Pathways Inc. is an affiliate of Orangeville Hydro Limited in that 66 2/3% of the shares are held by Orangeville Hydro Services Inc. which in turn is wholly owned by the Town of Orangeville. The other 33 1/3% shares in Green Pathways are owned by a non-profit group PURE (Power Up Renewable Energy).

Green Pathway's mandate is to promote energy conservation and renewable generation.

ORANGEVILLE HYDRO LIMITED 2008 ANNUAL REPORT:

The OHL 2008 Annual Report accompany this Schedule as Appendix I.

APPENDIX I

COPY OF Orangeville Hydro Limited

2008 ANNUAL REPORT

ORANGEVILLE HYDRO LIMITED
2008 ANNUAL REPORT

Background

Orangeville Hydro was established in 1916 serving its' customers under the regulatory control of Ontario Hydro. The Electricity Act was passed in 1998 and Orangeville Hydro Limited was incorporated on October 1, 2000. Orangeville Hydro Limited is a wires distribution business regulated by the Ontario Energy Board (OEB). As a distributor, we are responsible for delivering electricity and billing our customers approved distribution rates, commodity costs, and other regulatory charges. The OEB sets the distribution rates for Orangeville Hydro's customers based on an approved revenue requirement that provides for cost recovery and includes an approved rate of return. Orangeville Hydro Limited employed 20 employees in 2008.

Rate Application Information

The 2008 distribution rates were approved and implemented on May 1, 2008. This rate application was prepared using the Ontario Energy Board's guidelines for the 2nd Generation Incentive Rate Mechanism. There was a slight rate decrease comprised of the price escalator of 2.1% published by Stats Canada minus a productivity gain X factor of 1% resulting in an decrease in distribution rates of -.7%. The SMART meter rate adder of .27 remains in the distribution rates. The rate rider credit for regulatory assets ceased upon the implementation of the May 1st rates and resulted in an increase on customers' bills. A residential customer consuming 1,000 kWh per month received a 1.4% increase on the total bill.

Our 2nd Generation Incentive Rate Mechanism rate application for 2009 was approved. The application includes 2nd movement towards 60/40 debt to equity ratio, the price escalator adjustment for the Implicit Price Index for National Gross Domestic Product (GDP-IPI) of 2.3% for 2007, as published by Stats Canada minus a productivity gain X factor of 1%. The SMART meter adder on a customers' service charge of .27 cents per customer was increased to 1.00 in the application to assist with funding for our planned installations Fall 2009. The Ontario Energy Board directed all LDC's to increase the transmission network rate by 11.3% and the transmission connection rate by 5.2%. Orangeville Hydro has complied with this direction.

The Ontario Energy Board has established a multi-year rate setting plan and Orangeville Hydro is scheduled to apply for distribution rates in a cost of service application in 2010. A cost of service application involves a full review of costs and establishes an updated rate base that will be the foundation for the revenue requirement to set distribution rates. Regulatory assets/liabilities will be included in this process.

Merger of Orangeville Hydro Limited and Grand Valley Energy Inc.

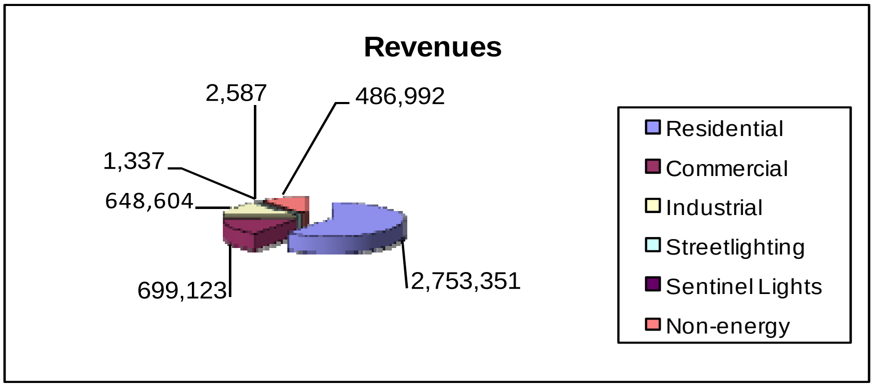
Effective January 1, 2009 Orangeville Hydro Limited and Grand Valley Energy Inc. merged companies for a total number of 10,975 customers to service. Grand Valley customers are familiar with Orangeville staff performing line work in the village and the excellent service provided by our customer service staff. With this in mind, the ‘brand’ of Orangeville Hydro will be kept as Orangeville Hydro Limited.

International Reporting Financial Standards

In 2006, the Canadian Accounting Standards Board announced its plan to replace current Canadian standards and interpretations governed by Canadian generally accepted accounting principles (GAAP) with International Financial Reporting Standards (IFRS) for all publicly accountable enterprises. The effective date of implementation is January 1, 2011. The change from Canadian GAAP to IFRS could significantly affect the reported financial position and the results of operations. In anticipation of the changes to our reporting standards due to the implementation of IFRS, Orangeville Hydro is currently assessing these changes in cooperation with the CHEC Group. It is expected that IFRS will be implemented in 2009 to ensure that 2010 has appropriate comparative financial information prior to effective implementation on January 1, 2011. Currently the Ontario Energy Board is consulting with stakeholders regarding specific guidance to rate-regulated industries. The areas of greatest impact to Orangeville Hydro will be in the financial presentation of property, plant and equipment, inventories, intangible assets, impairment of assets, employee benefits, and the methodology for revenue recognition.

Distribution Rates and Other Operation Revenues

The total revenues in the amount of $4,591,995 decreased from 2007 revenues by $77,526. Distribution revenues increased by $32,301 , due to the slight increase in distribution rates. The residential class of customers grew by 61 customers and 5 customers in the small general service class. The overall decrease in total revenue was due to the economic downturn and the reduction in interest rates that affected the interest we obtained on cash in the bank.

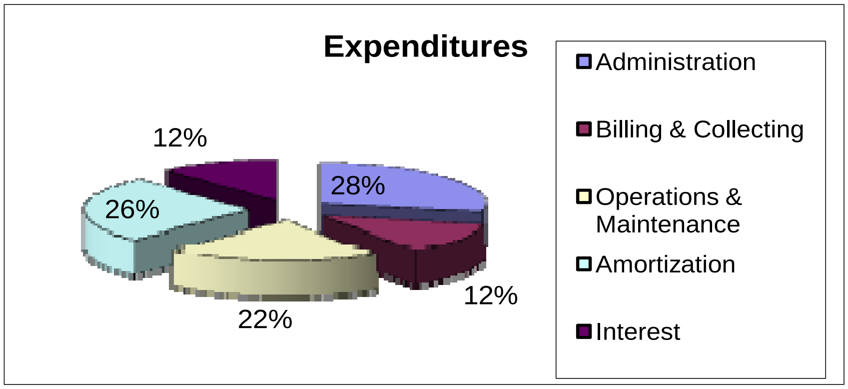


Expenditures

Total controllable expenses amounted to $2,200,263, an increase over last year by $121,546 or 5.8%. In administration, Orangeville Hydro has added a conservation and demand management/administrative person to the staff component. This staff person oversees the OPA programs and assists senior management in order for management to meet more demands as more regulatory measures evolve.

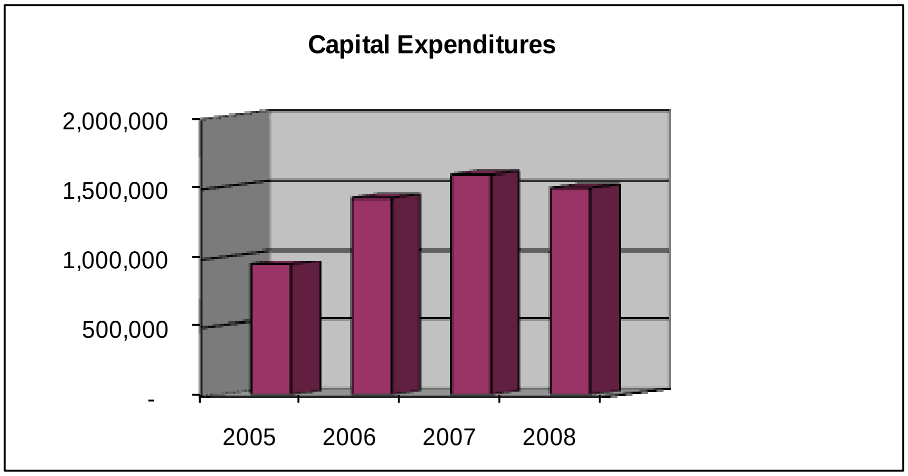
Controllable expenses per customer increased to $213.72 in relationship to the increase of our controllable costs. Even with this increase, Orangeville Hydro proudly remains as one of the lower cost ratios in our industry survey for medium-sized utilities.

Total expenditures amounted to $3,543,376, an overall increase over last year of .97%. Total expenditures include controllable expenses along with interest, amortization and capital tax expenses. Total interest of $409,882 includes interest on the long-term debt of $354,715 at a rate 5.59% held with TD Bank, carrying charges on the retail settlement variances plus customer deposit interest in the amount of $55,167.

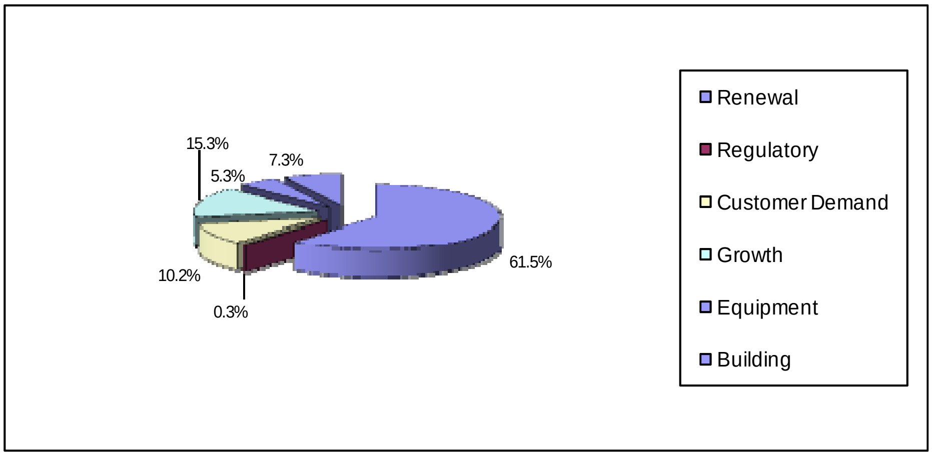


Capital Expenditures

In 2008 capital expenditures amounted to $1,492,908. Overhead renewal projects included ongoing conversion from 4kV to the 27.6kV on Townline, Green and Cardwell streets. The reliability and safety of the underground plant on Bredin Parkway was crucial in our decision for this underground renewal project. In 2009 we will rebuild the remaining portion. Customer Demand projects are new services and upgrades to services. The new services completed were Dairy Queen, the Rotomill plant and C Line condominiums and 3 service upgrades. Edgewood Valley, a new subdivision was energized in 2008 and consists of 58 new residences.

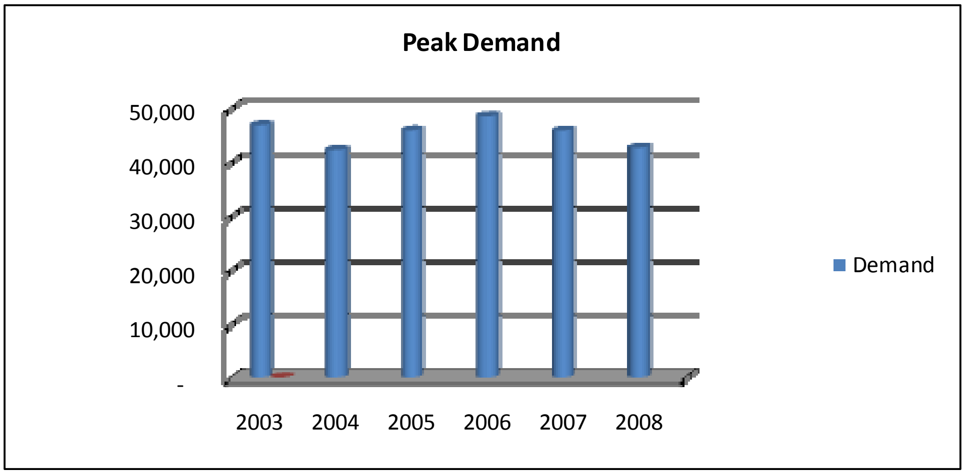


Of the $1,492,908 in Capital Expenditures, 61.5% of these dollars were related to Renewal Projects, 15.36% related to Growth, 10.2% related to Customer Demand Projects, .3% related to Regulatory projects, 5.3% related to Equipment and 7.3% related to Building.

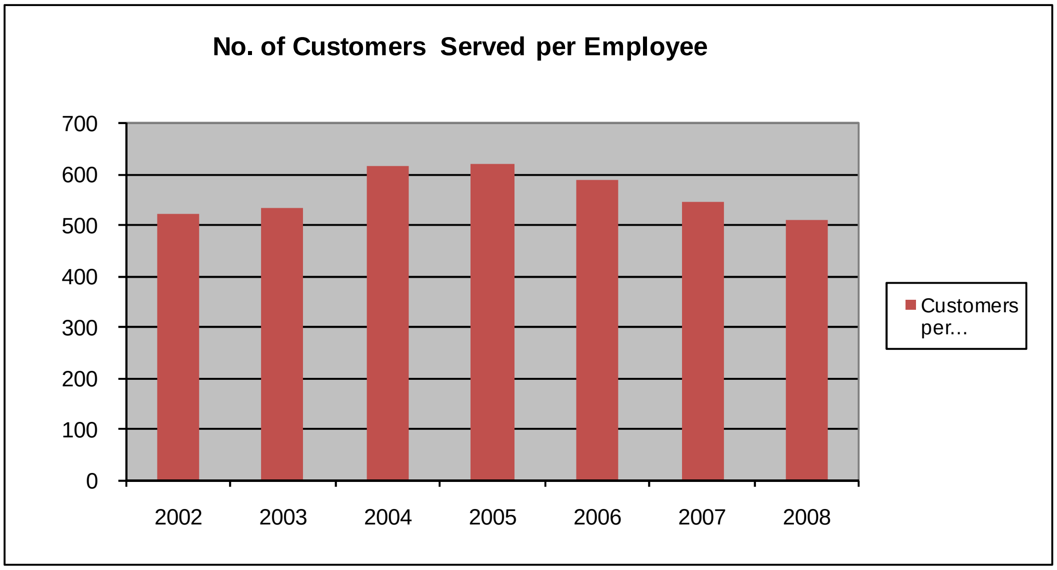


Operating Statistics

The system peak of 42,789 occurred in July, 2008. This is a reduction from the 2007 system peak at 46,047. The reduction relates to weather, conservation and demand initiatives and loss of an industrial customer. The system peak that occurred in July 2006 was 48,450 kilowatts and has become the record peak for Orangeville Hydro. The previous record peak was in 2003 where we recorded 47,090.



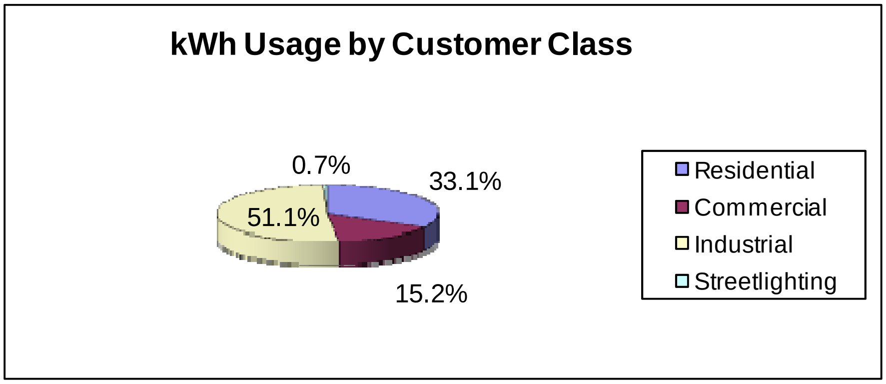
In 2008 the number of customers served per employee has decreased to 513.97. In order to maintain proficiency with the regulatory environment and conservation and demand management initiatives, it has been necessary to add an employee to our staff compliment. In the lines department we added an apprentice lineman November, 2007 in order to ensure succession planning needs are met. Orangeville Hydro also served customers in Grand Valley and their numbers are not reflected in these statistics. If they were included, the number of customers served per employee would be 548.75. Orangeville Hydro has still surpassed the year 2000 where we only served 498 customers per employee when there was no water billing and retailers to contend with.

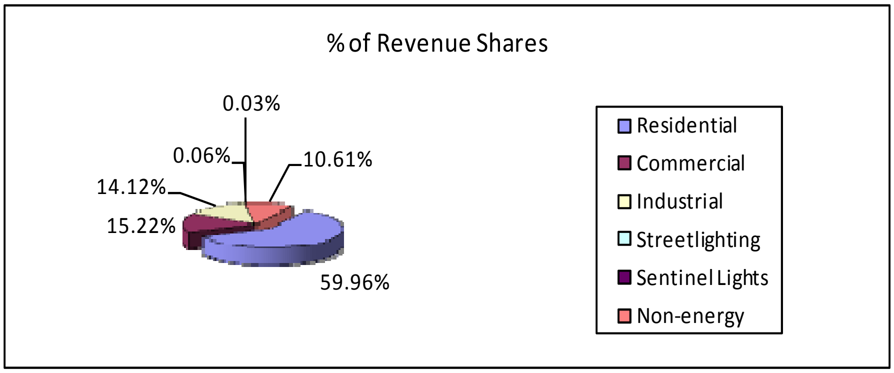


Customer Profile

Orangeville Hydro's residential customer base increased by 61 customers in 2008 and totaled 9056 customers. There was an increase 3 new customers in small general service class in 2008. There was no increase in the industrial customer base.

The industrial class of customers use 51.1% of the total kilowatt hours while the residential customer class attribute to the greater share of Orangeville Hydro's the total revenues.




% of Revenue Shares
0.03%
0.06%
10.61%
14.12%
15.22%
59.96%
Residential
Commercial
Industrial
Streetlighting
Sentinel Lights
Non-energy

ORANGEVILLE HYDRO LIMITED 2008 MANAGEMENT DISCUSSION AND ANALYSIS:

The OHL 2008 Management Discussion and Analysis accompany this schedule as Appendix J.

APPENDIX J

COPY OF Orangeville Hydro Limited

MANAGEMENT DISCUSSION AND ANALYSIS

BDO
Driving growth

BDO Dunwoody LLP
Chartered Accountants
and Advisors

77 Broadway, 2nd Floor
Orangeville, Ontario, Canada L9W 1K1
Telephone: (519) 941-0681
Fax: (519) 941-8272

March 2, 2009

Members of the Board of Directors
Orangeville Hydro Limited
400 C Line
PO Box 400, Station A
Orangeville, Ontario
L9W 2Z7

Re: Audit of the Financial Statements of Orangeville Hydro Limited
For the year ended December 31, 2008

Dear Sir/Madam:

The purpose of this report is to summarize certain aspects of the audit that we believe would be of interest to the Board of Directors. This report should be read in conjunction with the financial statements and our report thereon, and it is intended solely for the use of the Board of Directors and should not be distributed to external parties without our prior consent. We accept no responsibility to a third party who uses this communication.

Accounting Standards

The Canadian Institute of Chartered Accountants (CICA) has recently issued a number of new accounting standards. Most of these standards are fairly complex, require significant judgment and estimates, and may involve increased disclosures. Below, we have briefly outlined those which have impacted your organization:

- **IFRS Implementation Plan**

  With a January 1, 2011 changeover date, the following timeline should be considered:
  - 2008 - Continue to obtain training and knowledge of IFRSs. Compare current accounting policies to IFRS and develop a transition plan
  - December 31, 2008 - Disclosure of the anticipated effects of the change to IFRS in the MD&A for CSA registrants
  - December 31, 2009 - Disclosure of the anticipated effects of the change to IFRS in the MD&A for CSA registrants
  - January 1, 2010 - Begin collecting the comparative information which will be needed for inclusion with the 2011 financial statements
  - January 1, 2011- Changeover to IFRS
  - March 31, 2011- First quarterly IFRS financial statements, with IFRS quarterly comparatives
  - December 31, 2011- First annual IFRS financial statements, with IFRS annual comparatives

  At the 2011 changeover date, Canadian GAAP for publicly accountable enterprises will no longer be separate and distinct from IFRS; however, it is important to note that IFRS will be incorporated into the CICA Handbook.

Specific Accounting Standards

Topic	Effective Date	Guidance
Financial Instrument Disclosures and Presentation Section 3862 Section 3863	These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. Not-for-Profit Organizations may defer the application of the Section to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2008. Non-publicly accountable enterprises and certain co-operative business enterprises and rate-regulated enterprises may choose not to apply this Section.	Sections 3862 and 3863 comprise a complete set of disclosure and presentation requirements for financial instruments. They will carry forward unchanged the presentation requirements from Section 3861, however with much more extensive disclosure requirements. Section 3862 will require the disclosure of : • The significance of financial instruments for an entity's financial position and performance; and, • Qualitative and quantitative information about exposure to risks arising from financial instruments, including specified minimum disclosures about credit risk, liquidity risk and market risk. The qualitative disclosures would describe management's objectives, policies and processes for managing those risks. The quantitative disclosures would provide information about the extent to which the entity is exposed to risk, based on information provided internally to the entity's key management personnel.
Capital Disclosures Section 1535	This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. Earlier adoption is encouraged.	This section would require the disclosure of information about an entity's objectives, policies and processes for managing capital. This section applies to all entities, not just those with financial instruments.

Inventories Section 3031	This section applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008, with earlier application encouraged.	The key feature of this new section are: • Measurement of inventories at the lower of cost and net realizable value; • Guidance on the determination of cost, including allocation of overheads and other costs to inventory; • Allocation of fixed production overhead based on normal capacity levels, with unallocated overhead expensed as incurred; • Cost of inventories of items that are not ordinarily interchangeable, and goods or services produced and segregated for specific projects, assigned by using a specific identification of their individual costs; • Consistent use (by type of inventory with similar nature and use) of either first-in, first-out (FIFO) or weighted average cost formula to measure the cost of other inventories and eliminates the use of last-in, last out (LIFO) formula; and, • Reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories.

Income Taxes Section 3465	The amendments are effective for fiscal years beginning on or after January 1, 2009.	The Section has been amended to require rate-regulated enterprises to recognize future income tax liabilities and assets, as well as a regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to future customers, and to present these amounts on a gross basis in the financial statements.

Many of the above initiatives and pronouncements have an impact on the current year financial statements and will certainly have an impact in the years to come.

Independence

At the core of the provision of external audit services is the concept of independence. Canadian generally accepted auditing standards (GAAS) require us to communicate to the Board of Directors, at least annually, all relationships between BDO Dunwoody LLP (and its related entities) and Orangeville Hydro Limited (and its related entities), that, in our professional judgment, may reasonably be thought to bear on our independence for the audit of the organization.

In determining which relationships to report, we have considered the applicable legislation and relevant rules of professional conduct and related interpretations prescribed by the appropriate provincial institute/ordre covering such matters as the following:

- holding of a financial interest, either directly or indirectly in a client;
- holding a position, either directly or indirectly, that gives the right or responsibility to exert significant influence over the financial or accounting policies of a client;
- personal or business relationships of immediate family, close relatives, partners or retired partners, either directly or indirectly, with a client;
- economic dependence on a client; and
- provision of services in addition to the external audit engagement.

We have prepared the following comments to facilitate our discussion with you regarding independence matters arising since February 28, 2008, the date of our last letter.

We are not aware of any relationships between the organization and us that, in our professional judgment, may reasonably be thought to bear on our independence to date.

GAAS requires that we confirm our independence to the Board of Directors in the context of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario. Accordingly, we hereby confirm that we were independent with respect to Orangeville Hydro Limited within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario as of March 2, 2009.

Responsibilities of the Auditor

It is important for the Board of Directors to understand the responsibilities that rest with the organization and its management and those that belong to the auditor:

- Management is responsible for the preparation of the financial statements, which includes responsibilities related to internal control, such as designing and maintaining accounting records, selecting and applying accounting policies, safeguarding assets and preventing and detecting fraud and error;
- The auditor's responsibility is to express an opinion on the financial statements based on an audit thereof;
- An audit is performed to obtain reasonable, but not absolute, assurance as to whether the financial statements are free of material misstatement and, owing to the inherent limitations of an audit, there is an unavoidable risk that some misstatements of the financial statements will not be detected (particularly intentional misstatements concealed through collusion), even though the audit is properly planned and performed;
- The audit includes:
  - (i) obtaining an understanding of the entity and its environment including internal control in order to plan the audit and to assess the risk that the financial statements may contain misstatements that, individually or in the aggregate, are material to the financial statements taken as a whole;
  - (ii) examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements;
  - (iii) assessing the accounting principles used and their application; and
  - (iv) assessing the significant estimates made by management;
- When the auditor's risk assessment includes an expectation of the operating effectiveness of controls, sufficient appropriate audit evidence is obtained through tests of controls to support the assessment, but the scope of the auditor's review of internal control is insufficient to express an opinion as to the effectiveness or efficiency of the entity's controls; and
- We expressed an opinion as to whether the financial statements presented fairly in all material respects, in accordance with Canadian generally accepted accounting principles, the financial position, results of operations and cash flows of the entity.

Audit Approach

We were engaged to perform the audit of the financial statements of Orangeville Hydro Limited for the year ended December 31, 2008. We adopted an audit approach that allowed us to issue an audit opinion on the financial statements of the organization in the most cost effective manner, while still obtaining the assurance necessary to support our audit opinion.

BDO Dunwoody LLP follows a risk based approach. This approach focuses on obtaining sufficient appropriate audit evidence to reduce the risk of material misstatement in the financial statements to an appropriately low level. This means that we focus our audit effort in areas that we believe have a higher risk of being materially misstated and do less audit work in areas that are only low risk.

To assess risk accurately, we need to have a clear understanding of the organization's business and the environment it operates in. Much of our understanding is obtained through discussions with management and their staff. We appreciate the information that you provided to us about your business, industry, competitive marketplace, internal controls, oversight of management's processes relating to fraud and error, or anything else that you felt was important to the audit as it corroborated what we had already learned from management and other sources, or it may have been new information to us. We also appreciate the insights that you provided to us on what you perceived to be risky in your organization, including your knowledge of actual, suspected and alleged fraud affecting the entity, as that made our audit more effective and efficient, which benefited all concerned.

The following sections provide more detail on our audit approach for Orangeville Hydro Limited for the year.

Overall Audit Strategy

The general audit strategies available to us are a "combined" audit approach or a "substantive" audit approach.

In a combined audit approach, we would obtain our assurance from a combination of tests of controls (compliance procedures) and substantive procedures (such as analysis of data and obtaining direct evidence as to the validity of the items). The combined strategy is more appropriate when there is a large number of transactions and when controls in the organization are strong. By obtaining some of our assurance from tests of controls, we can reduce the substantive procedures that need to be done. Under a substantive audit approach, all of our audit evidence is obtained through substantive procedures like analysis, confirmation, examination of documentary or electronic evidence, etc.

Based on our knowledge and experience with your organization and a preliminary review of your internal controls, we used a combined approach.

Likely Aggregate Misstatements

Uncorrected misstatements aggregated during the audit that were determined by management to be immaterial amounted to $32,994. The major unadjusted misstatements are as follows:

• Understatement of income due to 2007 regulatory asset refunds recorded in 2008 instead of included with 2007 unbilled revenue	$ 32,480
• To write off credit balance in transition account as in prior years	12,260
• Effect of previous year's errors	(11,746)
Total Likely Aggregate Misstatements	$ 32,994

After considering both quantitative and qualitative factors with respect to the likely aggregate misstatements above, we agree with management that the financial statements are not materially misstated.

Management Representations

During the course of an audit, management made many representations to us. These representations were verbal or written and therefore explicit, or they were implied through the financial statements. Management provided representations in response to specific queries from us, as well as unsolicited representations. Such representations were part of the evidence gathered by us to be able to draw reasonable conclusions on which to base the audit opinion. These representations were documented by including in the audit working papers memoranda of discussions with management and written representations received from management.

Management's representations included, but were not limited to:

(a) matters communicated in discussions with us, whether solicited or unsolicited;

(b) matters communicated electronically to us;

(c) schedules, analyses and reports prepared by the entity, and management's notations and comments thereon, whether or not in response to a request by us;

(d) internal and external memoranda or correspondence;

(e) minutes of meetings of the board of directors or similar bodies such as audit committees and compensation committees;

(f) a signed copy of the financial statements; and

(g) a representation letter from management.

We obtained management's written confirmation of significant representations provided to us during the engagement. Such a confirmation included matters that are:

(a) directly related to items that are material, either individually or in the aggregate, to the financial statements;

(b) not directly related to items that are material to the financial statements but are significant, either individually or in the aggregate, to the engagement; or

(c) relevant to management's judgments or estimates that are material, either individually or in the aggregate, to the financial statements.

Management's responsibility for the implementation of International Financial Reporting Standards (IFRS)

We are not responsible for ensuring that the organization is prepared for the introduction of IFRS, and this will only be considered in so far as it affects our audit responsibilities under Canadian Generally Accepted Auditing Standards.

Management is responsible for:

- analyzing the impact of the introduction of IFRS on the business;
- developing plans to mitigate the effects identified by this analysis; and
- the preparation of financial statements as required under IFRS, including comparative figures.

IFRS Services

If assistance or additional services are required related to the organization's adoption of IFRS we shall confirm them with you as they arise.

Our Audit Opinion

We did not detect any evidence of misstatements that would have a material effect on the financial statements and, accordingly, we have issued an unqualified audit report.

Management Letter

We have submitted to management a letter on internal controls and other matters that we feel should be brought to their attention.

We wish to express our appreciation for the co-operation we received during the audit from the organization's management. We would be pleased to discuss with you any matters mentioned in this letter, as well as any other matters that may be of interest to you.

Yours truly

BDO DUNWOODY LLP
Chartered Accountants, Licensed Public Accountants

Sally Slumskie, CA
Partner

BDO

BDO Dunwoody LLP
Chartered Accountants
and Advisors

77 Broadway, 2nd Floor
Orangeville, Ontario, Canada L9W 1K1
Telephone: (519) 941-0681
Fax: (519) 941-8272

March 2, 2009

Members of the Board of Directors
Grand Valley Energy Inc.
400 C Line
PO Box 400, Station A
Orangeville, Ontario
L9W 2Z7

Re: Audit of the Financial Statements of Grand Valley Energy Inc.
For the year ended December 31, 2008

Dear Sir/Madam:

The purpose of this report is to summarize certain aspects of the audit that we believe would be of interest to the Board of Directors. This report should be read in conjunction with the financial statements and our report thereon, and it is intended solely for the use of the Board of Directors and should not be distributed to external parties without our prior consent. We accept no responsibility to a third party who uses this communication.

Accounting Standards

The Canadian Institute of Chartered Accountants (CICA) has recently issued a number of new accounting standards. Most of these standards are fairly complex, require significant judgment and estimates, and may involve increased disclosures. Below, we have briefly outlined those which have impacted your organization:

- **IFRS Implementation Plan**

  With a January 1, 2011 changeover date, the following timeline should be considered:
  - 2008 - Continue to obtain training and knowledge of IFRSs. Compare current accounting policies to IFRS and develop a transition plan
  - December 31, 2008 - Disclosure of the anticipated effects of the change to IFRS in the MD&A for CSA registrants
  - December 31, 2009 - Disclosure of the anticipated effects of the change to IFRS in the MD&A for CSA registrants
  - January 1, 2010 - Begin collecting the comparative information which will be needed for inclusion with the 2011 financial statements
  - January 1, 2011- Changeover to IFRS
  - March 31, 2011- First quarterly IFRS financial statements, with IFRS quarterly comparatives
  - December 31, 2011- First annual IFRS financial statements, with IFRS annual comparatives

At the 2011 changeover date, Canadian GAAP for publicly accountable enterprises will no longer be separate and distinct from IFRS; however, it is important to note that IFRS will be incorporated into the CICA Handbook.

Specific Accounting Standards

Topic	Effective Date	Guidance
Financial Instrument Disclosures and Presentation Section 3862 Section 3863	These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. Not-for-Profit Organizations may defer the application of the Section to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2008. Non-publicly accountable enterprises and certain co-operative business enterprises and rate-regulated enterprises may choose not to apply this Section.	Sections 3862 and 3863 comprise a complete set of disclosure and presentation requirements for financial instruments. They will carry forward unchanged the presentation requirements from Section 3861, however with much more extensive disclosure requirements. Section 3862 will require the disclosure of : • The significance of financial instruments for an entity's financial position and performance; and, • Qualitative and quantitative information about exposure to risks arising from financial instruments, including specified minimum disclosures about credit risk, liquidity risk and market risk. The qualitative disclosures would describe management's objectives, policies and processes for managing those risks. The quantitative disclosures would provide information about the extent to which the entity is exposed to risk, based on information provided internally to the entity's key management personnel.

Income Taxes Section 3465	The amendments are effective for fiscal years beginning on or after January 1, 2009.	The Section has been amended to require rate-regulated enterprises to recognize future income tax liabilities and assets, as well as a regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or returned to future customers, and to present these amounts on a gross basis in the financial statements.

The above initiatives and pronouncements will have an impact on subsequent year's financial statements.

Independence

At the core of the provision of external audit services is the concept of independence. Canadian generally accepted auditing standards (GAAS) require us to communicate to the Board of Directors, at least annually, all relationships between BDO Dunwoody LLP (and its related entities) and Grand Valley Energy Inc. (and its related entities), that, in our professional judgment, may reasonably be thought to bear on our independence for the audit of the organization.

In determining which relationships to report, we have considered the applicable legislation and relevant rules of professional conduct and related interpretations prescribed by the appropriate provincial institute/ordre covering such matters as the following:

- holding of a financial interest, either directly or indirectly in a client;
- holding a position, either directly or indirectly, that gives the right or responsibility to exert significant influence over the financial or accounting policies of a client;
- personal or business relationships of immediate family, close relatives, partners or retired partners, either directly or indirectly, with a client;
- economic dependence on a client; and
- provision of services in addition to the external audit engagement.

We have prepared the following comments to facilitate our discussion with you regarding independence matters arising since February 28, 2008, the date of our last letter.

We are not aware of any relationships between the organization and us that, in our professional judgment, may reasonably be thought to bear on our independence to date.

GAAS requires that we confirm our independence to the Board of Directors in the context of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario. Accordingly, we hereby confirm that we were independent with respect to Grand Valley Energy Inc. within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario as of March 2, 2009.

Responsibilities of the Auditor

It is important for the Board of Directors to understand the responsibilities that rest with the organization and its management and those that belong to the auditor:

- Management is responsible for the preparation of the financial statements, which includes responsibilities related to internal control, such as designing and maintaining accounting records, selecting and applying accounting policies, safeguarding assets and preventing and detecting fraud and error;
- The auditor's responsibility is to express an opinion on the financial statements based on an audit thereof;
- An audit is performed to obtain reasonable, but not absolute, assurance as to whether the financial statements are free of material misstatement and, owing to the inherent limitations of an audit, there is an unavoidable risk that some misstatements of the financial statements will not be detected (particularly intentional misstatements concealed through collusion), even though the audit is properly planned and performed;
- The audit includes:
  - (i) obtaining an understanding of the entity and its environment including internal control in order to plan the audit and to assess the risk that the financial statements may contain misstatements that, individually or in the aggregate, are material to the financial statements taken as a whole;
  - (ii) examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements;
  - (iii) assessing the accounting principles used and their application; and
  - (iv) assessing the significant estimates made by management;
- When the auditor's risk assessment includes an expectation of the operating effectiveness of controls, sufficient appropriate audit evidence is obtained through tests of controls to support the assessment, but the scope of the auditor's review of internal control is insufficient to express an opinion as to the effectiveness or efficiency of the entity's controls; and
- We expressed an opinion as to whether the financial statements presented fairly in all material respects, in accordance with Canadian generally accepted accounting principles, the financial position, results of operations and cash flows of the entity.

Audit Approach

We were engaged to perform the audit of the financial statements of Grand Valley Energy Inc. for the year ended December 31, 2008. We adopted an audit approach that allowed us to issue an audit opinion on the financial statements of the organization in the most cost effective manner, while still obtaining the assurance necessary to support our audit opinion.

BDO Dunwoody LLP follows a risk based approach. This approach focuses on obtaining sufficient appropriate audit evidence to reduce the risk of material misstatement in the financial statements to an appropriately low level. This means that we focus our audit effort in areas that we believe have a higher risk of being materially misstated and do less audit work in areas that are only low risk.

To assess risk accurately, we need to have a clear understanding of the organization's business and the environment it operates in. Much of our understanding is obtained through discussions with management and their staff. We appreciate the information that you provided to us about your business, industry, competitive marketplace, internal controls, oversight of management's processes relating to fraud and error, or anything else that you felt was important to the audit as it corroborated what we had already learned from management and other sources, or it may have been new information to us. We also appreciate the insights that you provided to us on what you perceived to be risky in your organization, including your knowledge of actual, suspected and alleged fraud affecting the entity, as that made our audit more effective and efficient, which benefited all concerned.

The following sections provide more detail on our audit approach for Grand Valley Energy Inc. for the year.

Overall Audit Strategy

The general audit strategies available to us are a "combined" audit approach or a "substantive" audit approach.

In a combined audit approach, we would obtain our assurance from a combination of tests of controls (compliance procedures) and substantive procedures (such as analysis of data and obtaining direct evidence as to the validity of the items). The combined strategy is more appropriate when there is a large number of transactions and when controls in the organization are strong. By obtaining some of our assurance from tests of controls, we can reduce the substantive procedures that need to be done. Under a substantive audit approach, all of our audit evidence is obtained through substantive procedures like analysis, confirmation, examination of documentary or electronic evidence, etc.

Based on our knowledge and experience with your organization and a preliminary review of your internal controls, we used a combined approach.

Likely Aggregate Misstatements

Uncorrected misstatements aggregated during the audit that were determined by management to be immaterial amounted to $6,303. The major unadjusted misstatements are as follows:

• Overstatement of income due to 2007 regulatory asset recoveries recorded in 2008 instead of included with 2007 unbilled revenue	$ 5,430
Total Likely Aggregate Misstatements	$ 5,430

After considering both quantitative and qualitative factors with respect to the likely aggregate misstatements above, we agree with management that the financial statements are not materially misstated.

Management Representations

During the course of an audit, management made many representations to us. These representations were verbal or written and therefore explicit, or they were implied through the financial statements. Management provided representations in response to specific queries from us, as well as unsolicited representations. Such representations were part of the evidence gathered by us to be able to draw reasonable conclusions on which to base the audit opinion. These representations were documented by including in the audit working papers memoranda of discussions with management and written representations received from management.

Management's representations included, but were not limited to:

(a) matters communicated in discussions with us, whether solicited or unsolicited;

(b) matters communicated electronically to us;

(c) schedules, analyses and reports prepared by the entity, and management's notations and comments thereon, whether or not in response to a request by us;

(d) internal and external memoranda or correspondence;

(e) minutes of meetings of the board of directors or similar bodies such as audit committees and compensation committees;

(f) a signed copy of the financial statements; and

(g) a representation letter from management.

We obtained management's written confirmation of significant representations provided to us during the engagement. Such a confirmation included matters that are:

(a) directly related to items that are material, either individually or in the aggregate, to the financial statements;

(b) not directly related to items that are material to the financial statements but are significant, either individually or in the aggregate, to the engagement; or

(c) relevant to management's judgments or estimates that are material, either individually or in the aggregate, to the financial statements.

Management's responsibility for the implementation of International Financial Reporting Standards (IFRS)

We are not responsible for ensuring that the organization is prepared for the introduction of IFRS, and this will only be considered in so far as it affects our audit responsibilities under Canadian Generally Accepted Auditing Standards.

Management is responsible for:

- analyzing the impact of the introduction of IFRS on the business;
- developing plans to mitigate the effects identified by this analysis; and
- the preparation of financial statements as required under IFRS, including comparative figures.

IFRS Services

If assistance or additional services are required related to the organization's adoption of IFRS we shall confirm them with you as they arise.

Our Audit Opinion

We did not detect any evidence of misstatements that would have a material effect on the financial statements and, accordingly, we have issued an unqualified audit report.

Management Letter

We have submitted to management a letter on internal controls and other matters that we feel should be brought to their attention.

We wish to express our appreciation for the co-operation we received during the audit from the organization's management. We would be pleased to discuss with you any matters mentioned in this letter, as well as any other matters that may be of interest to you.

Yours truly

BDO DUNWOODY LLP
Chartered Accountants, Licensed Public Accountants

Sally Slumskie

Sally Slumskie, CA
Partner

ORANGEVILLE HYDRO LIMITED REVENUE REQUIREMENT WORK FORM:

The OHL Revenue Requirement Work Form accompany this schedule as Appendix K.

APPENDIX K

REVENUE REQUIREMENT WORK FORM

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orangeville Hydro Limited
File Number:
Rate Year: 2010

Data Input **(1)**

		Application		Adjustments	Per Board Decision	
1	**Rate Base**					
	Gross Fixed Assets (average)	$31,947,331	**(4)**		$31,947,331	
	Accumulated Depreciation (average)	($17,513,537)	**(5)**		($17,513,537)	
	Allowance for Working Capital:					
	Controllable Expenses	$2,769,015	(6)		$2,769,015	
	Cost of Power	$19,666,513			$19,666,513	
	Working Capital Rate (%)	15.00%				
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$4,374,574				
	Distribution Revenue at Proposed Rates	$5,005,962				
	Other Revenue:					
	Specific Service Charges	$159,163				
	Late Payment Charges	$37,522				
	Other Distribution Revenue	$100,592				
	Other Income and Deductions	$58,995				
	Operating Expenses:					
	OM+A Expenses	$2,769,015			$2,769,015	
	Depreciation/Amortization	$1,119,762			$1,119,762	
	Property taxes					
	Capital taxes	$2,099				
	Other expenses					
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	$41,959	**(3)**			
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$176,574	cir			
	Income taxes (grossed up)	$248,138				
	Capital Taxes	$2,099	cir			
	Federal tax (%)	18.00%				
	Provincial tax (%)	10.84%				
	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 (%)	6.5%				
	Short-term debt Cost Rate (%)	1.3%				
	Common Equity Cost Rate (%)	8.0%				
	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.

Other Distribution Revenue: Amount of $101,867 is not included in OHL's revenue offsets for:
Water/Sewer Billing, $98,860, Variance AC Interest, $2,387, 50% of Gain on Disposal,$800

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orangeville Hydro Limited
File Number:
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$31,947,331	$ -	$31,947,331
2	Accumulated Depreciation (average)	(3)	($17,513,537)	$ -	($17,513,537)
3	Net Fixed Assets (average)	(3)	$14,433,794	$ -	$14,433,794
4	Allowance for Working Capital	(1)	$3,365,329	$ -	$3,365,329
5	**Total Rate Base**		$17,799,123	$ -	$17,799,123

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$2,769,015	$ -	$2,769,015
7	Cost of Power		$19,666,513	$ -	$19,666,513
8	Working Capital Base		$22,435,528	$ -	$22,435,528
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$3,365,329	$ -	$3,365,329

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: Orangeville Hydro Limited
File Number:
Rate Year: 2010

			Utility income		
Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$5,005,962	$ -	$5,005,962
2	Other Revenue	**(1)**	$356,272	$ -	$356,272
3	Total Operating Revenues		$5,362,234	$ -	$5,362,234
	Operating Expenses:				
4	OM+A Expenses		$2,769,015	$ -	$2,769,015
5	Depreciation/Amortization		$1,119,762	$ -	$1,119,762
6	Property taxes		$ -	$ -	$ -
7	Capital taxes		$2,099	$ -	$2,099
8	Other expense		$ -	$ -	$ -
9	Subtotal		$3,890,877	$ -	$3,890,877
10	Deemed Interest Expense		$652,936	$ -	$652,936
11	Total Expenses (lines 4 to 10)		$4,543,812	$ -	$4,543,812
12	**Utility income before income taxes**		$818,422	$ -	$818,422
13	Income taxes (grossed-up)		$248,138	$ -	$248,138
14	**Utility net income**		$570,284	$ -	$570,284

Notes

(1)	**Other Revenues / Revenue Offsets**		
	Specific Service Charges	$159,163	$159,163
	Late Payment Charges	$37,522	$37,522
	Other Distribution Revenue	$100,592	$100,592
	Other Income and Deductions	$58,995	$58,995
	Total Revenue Offsets	$356,272	$356,272

Other Income and Deductions does not include the Water/Sewer Billing, Interest on Regulatory Asset and 50% of Gain on Disposal of Asset of $800 ($1600*50%) for the forecasted gain in 2010

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orangeville Hydro Limited
File Number:
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$570,284	$570,284
2	Adjustments required to arrive at taxable utility income	$41,959	$41,959
3	Taxable income	$612,243	$612,243
	Calculation of Utility income Taxes		
4	Income taxes	$176,574	$176,574
5	Capital taxes	$2,099	$2,099
6	Total taxes	$178,673	$178,673
7	Gross-up of Income Taxes	$71,564	$71,564
8	Grossed-up Income Taxes	$248,138	$248,138
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$250,237	$250,237
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	18.00%	18.00%
12	Provincial tax (%)	10.84%	10.84%
13	Total tax rate (%)	28.84%	28.84%

Notes

Table income is below 1.5 million and tax is calculated on the first $500,000 at 5.5% and the remaining at 18.25% to result in an effective tax rate of 28.84%

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orangeville Hydro Limited
File Number:
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$9,967,509	6.46%	$643,467
2	Short-term Debt	4.00%	$711,965	1.33%	$9,469
3	**Total Debt**	60.00%	$10,679,474	6.11%	$652,936
	Equity				
4	Common Equity	40.00%	$7,119,649	8.01%	$570,284
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$7,119,649	8.01%	$570,284
7	**Total**	100%	$17,799,123	6.87%	$1,223,220
	Per Board Decision				
		(%)	($)	(%)	
	Debt				
8	Long-term Debt	56.00%	$9,967,509	6.46%	$643,467
9	Short-term Debt	4.00%	$711,965	1.33%	$9,469
10	**Total Debt**	60.00%	$10,679,474	6.11%	$652,936
	Equity				
11	Common Equity	40.0%	$7,119,649	8.01%	$570,284
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$7,119,649	8.01%	$570,284
14	**Total**	100%	$17,799,123	6.87%	$1,223,220

Notes

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

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orangeville Hydro Limited
File Number:
Rate Year: 2010

		Revenue Sufficiency/Deficiency			
		Per Application		Per Board Decision	
Line No.	Particulars	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$631,388		$631,388
2	Distribution Revenue	$4,374,574	$4,374,574	$4,374,574	$4,374,574
3	Other Operating Revenue Offsets - net	$356,272	$356,272	$356,272	$356,272
4	**Total Revenue**	$4,730,846	$5,362,234	$4,730,846	$5,362,234
5	Operating Expenses	$3,890,877	$3,890,877	$3,890,877	$3,890,877
6	Deemed Interest Expense	$652,936	$652,936	$652,936	$652,936
	Total Cost and Expenses	$4,543,812	$4,543,812	$4,543,812	$4,543,812
7	**Utility Income Before Income Taxes**	$187,034	$818,422	$187,034	$818,422
8	Tax Adjustments to Accounting Income per 2009 PILs	$41,959	$41,959	$41,959	$41,959
9	**Taxable Income**	$228,993	$860,381	$228,993	$860,381
10	Income Tax Rate	28.84%	28.84%	28.84%	28.84%
11	**Income Tax on Taxable Income**	$66,043	$248,138	$66,043	$248,138
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$120,991	$570,284	$120,991	$570,284
14	**Utility Rate Base**	$17,799,123	$17,799,123	$17,799,123	$17,799,123
	Deemed Equity Portion of Rate Base	$7,119,649	$7,119,649	$7,119,649	$7,119,649
15	Income/Equity Rate Base (%)	1.70%	8.01%	1.70%	8.01%
16	Target Return - Equity on Rate Base	8.01%	8.01%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-6.31%	0.00%	-6.31%	0.00%
17	Indicated Rate of Return	4.35%	6.87%	4.35%	6.87%
18	Requested Rate of Return on Rate Base	6.87%	6.87%	6.87%	6.87%
19	Sufficiency/Deficiency in Rate of Return	-2.52%	0.00%	-2.52%	0.00%
20	Target Return on Equity	$570,284	$570,284	$570,284	$570,284
21	Revenue Sufficiency/Deficiency	$449,293	($0)	$449,293	($0)
22	**Gross Revenue Sufficiency/Deficiency**	$631,388 **(1)**		$631,388 **(1)**	

Notes:

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

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orangeville Hydro Limited
File Number:
Rate Year: 2010

		Revenue Requirement	
Line No.	**Particulars**	**Application**	**Per Board Decision**
1	OM&A Expenses	$2,769,015	$2,769,015
2	Amortization/Depreciation	$1,119,762	$1,119,762
3	Property Taxes	$ -	$ -
4	Capital Taxes	$2,099	$2,099
5	Income Taxes (Grossed up)	$248,138	$248,138
6	Other Expenses	$ -	$ -
7	Return		
	Deemed Interest Expense	$652,936	$652,936
	Return on Deemed Equity	$570,284	$570,284
8	Distribution Revenue Requirement before Revenues	$5,362,234	$5,362,234
9	Distribution revenue	$5,005,962	$5,005,962
10	Other revenue	$356,272	$356,272
11	**Total revenue**	$5,362,234	$5,362,234
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ - **(1)**	$ - **(1)**

Notes

(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orangeville Hydro Limited
File Number:
Rate Year: 2010

Ontario

Selected Delivery Charge and Bill Impacts
Per Draft Rate Order

		Monthly Delivery Charge					Total Bill			
			Per Draft	Change				Per Draft	Change	
		Current	Rate Order	$	%		Current	Rate Order	$	%
Residential	**1000** kWh/month	$ 30.57	$ 31.48	$ 0.91	3.0%		$ 122.36	$ 123.81	$ 1.45	1.2%
GS < 50kW	**2000** kWh/month	$ 50.98	$ 54.05	$ 3.07	6.0%		$ 236.78	$ 241.00	$ 4.21	1.8%

Notes:

OHL could not include the bill impacts for the Grand Valley service area so we used Orangeville Hydro rate to calculate impact.
Monthly Delivery includes distribution service charge, volumetric and rate riders.
Total Bill includes commodity Transmission, WMS, debt retirement and taxes

RATE BASE:

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application follows the definition used in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2010 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

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

OHL has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year in Table 1 below. OHL has calculated its 2010 rate base as $17,799,123.

Table 1
Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Gross Fixed Assets	24,862,719	26,983,585	28,016,813	29,276,036	30,979,862	32,914,799
Accumulated Depreciation	(11,663,237)	(13,739,390)	(14,770,385)	(15,767,852)	(16,912,687)	(18,114,388)
Net Book Value	13,199,482	13,244,195	13,246,428	13,508,184	14,067,176	14,800,412
Average Net Book Value	13,199,482	13,121,369	13,245,312	13,377,306	13,787,680	14,433,794
Working Capital	18,196,017	20,047,040	21,017,501	20,480,378	22,288,633	22,435,528
Working Capital Allowance	2,729,402	3,007,056	3,152,625	3,072,057	3,343,295	3,365,329
Rate Base	15,928,885	16,128,425	16,397,937	16,449,363	17,130,975	17,799,123

OHL has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year in Table 2, below. Details of OHL's calculation of its working capital allowance are provided at Exhibit 2, Tab 4, Schedule 1.

Table 2
Summary of Working Capital Calculation

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Cost of Power	15,986,825	17,998,434	18,732,324	18,215,238	19,919,438	19,666,513
Operations	199,733	248,806	271,145	338,920	319,390	408,946
Maintenance	378,794	339,366	445,480	457,999	447,677	492,423
Billing & Collecting	470,174	476,660	483,587	501,713	508,659	559,953
Community	24,957	151,591	168,331	42,551	12,584	28,862
Administration & General Expense	1,135,533	850,229	936,592	1,066,947	1,080,885	1,278,832
Working Capital	18,196,017	20,065,087	21,037,459	20,623,368	22,288,633	22,435,528

The OHL Distribution System:

OHL owns and operates the electricity distribution system in its licensed service area in the Town of Orangeville and the Village of Grand Valley, serving approximately 14,303 Residential, General Service, Street Light, Sentinel Light and Unmetered Scattered Load customers/connections.

OHL's supply for the Town of Orangeville comes through the Hydro One transmission system at primary voltages of 44.0 kV and 27.6 kV. Electricity is then distributed through OHL's service area of 16 square kilometres, over 66 kilometres of underground cable and 95 kilometres of overhead conductor. OHL delivers electricity at its primary supply voltage to the General Service >50 kW (44 kV delta, 27.6 kV wye), General Service (27.6, 8 or 4 kV wye) and Residential (16.0, 4.8 or 2.4 kV) customers. Primary voltage is stepped down through 5 OHL-owned distribution stations to service General Service (347/600 wye 600 delta, 240 delta, 120/208 wye, three phase) and Residential (120/240 single phase) customers. Voltage is stepped down from the 27.6, 8, and 4.16 kV primary feeders through approximately 1,388 LDC owned distribution transformers. OHL's supply for the Village of Grand Valley comes through the Hydro One distribution station at 44 kV. Electricity is then distributed through OHL's service area of 1 square kilometre, over 1 kilometre of underground cable and 8 kilometres of overhead conductor.

In the 2010 capital budget OHL will procure the services of an engineering consultant to analyze and optimize our overall system and to assist in developing a more comprehensive strategy for our Asset Management plan. Under advisory of the engineering consultant, OHL will begin implementation of a supervisory control and data acquisition system and GIS system. Several interested parties have contacted OHL to connect renewable generation to our system. OHL is committed to the Green Energy Act and the intent to have Smart Grid which allows customers with generation to connect.

OHL owns and maintains approximately 11,258 meters installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW and kVA demand as well as hourly interval data. OHL will be installing smart meters in the Spring of 2010 as part of the Province of Ontario's smart meter initiative. On June 25, 2009, Ontario Regulation 235/08 was filed by the Ontario Provincial Government giving Orangeville Hydro Limited authorization to proceed with its first phase of Smart Meter installation. The proposed revenue requirement does not include costs related to Smart Meters.

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

On an annual basis, OHL reviews capital projects identified for potential implementation and attempts to prioritize each project based on defined criteria on a relative basis. All members of the management team follow the criteria as they individually complete their work on preparing outlines of their recommendations, which are then discussed by the full group. After examining all recommended projects they are listed in order from higher to lower priority and then moved forward based on appropriate financial parameters.

In addition to the capital needs of the network, OHL provides for maintenance planning for the assets. The same preparation and consideration steps are undertaken before the Finance department establishes the recommended budget amounts. Further information on OHL's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

OHL assets fall into two broad categories – distribution plant, which includes assets such as substation building, wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and general plant which includes assets such as, office building and service centre, computer equipment and software. More detailed lists of distribution and general plant categories can be found in the Gross Assets Table at Exhibit 2, Tab 2, Schedule 2.

Capital Projects:

OHL's capital budget items include:

- **Customer Demand:**

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

Renewal:

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

- **Security:**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for OHL.

- **Capacity:**

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

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve OHL reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of OHL’s distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by OHL. The Asset Management Report provided in Exhibit 2, Tab 3, Schedule 3 supports the capital and maintenance programs needed to maintain and enhance the reliability of OHL's distribution system.

- **Regulatory Requirements:**

These projects are system capital investments, which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment and the Town of Orangeville or the Village of Grand Valley, relocating system plant for roadway reconstruction work. Where projects are municipally driven, OHL follows the regulations of road reconstruction work collecting contributed capital for 50% of the labour and vehicles. In 2009 and 2010 OHL has also placed into this category those projects relating to the elimination of long-term load transfers pursuant to the DSC.

- **Substations:**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. The renewal or retirement of OHL's 4.16 kV substations is the subject of a review being undertaken as part of the Asset Management Report. Since 1985, OHL has been expanding the 27.6kV system with the objective of eliminating some of the 4.16kV network, which could eventually lead to a reduction in the number of distribution stations, reduced number of distribution feeders and improved efficiency in the delivery of electricity. Continuation of this conversion program will maximize the amount of the distributed generation allowed to connect under the Green Energy Act.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. OHL is initiating a smart meter program, as approved by Ontario Regulation 235/08 (Authorized Discretionary Metering Activity & Procurement).

- **Green Energy Act Enablement:**

Capital expenditures in this pool are for the promotion of renewable energy, the timely connection of renewable projects to OHL's distribution system, the promotion of demand management and facilitation of the Smart Grid.

OHL capital projects for the 2010 Test Year are discussed in further detail. OHL has provided project-specific justifications in Exhibit 2, Tab 3, Schedule 2 for the 2009 Bridge Year and 2010 Test Year. OHL's 2010 revenue requirement amounts to $5,362,234 and written explanations have been provided for rate base-related variances that exceed materiality of $50,000 (distributors with a distribution revenue requirement of less than or equal to $10 million, being the materiality threshold in the Filing Requirements).

Gross Assets – Property, Plant and Equipment and Accumulated Depreciation:

The 2009 Bridge and 2010 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. An analysis of our 2006 to 2010 capital programs are described in detail in OHL's written evidence at Exhibit 2, Tab 3, Schedule 1.

The following comments provide an overview of OHL's budgeting process.

- **Overall Budget Process:**

The budget is prepared annually by management and is reviewed and approved by the OHL Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

- **Responsibilities:**

> It is the responsibility of the Finance department to coordinate the development of the operating budget, capital budget and forecast processes.

> Each department is responsible for preparing its operating budget, capital budget, and rolling forecasts.

> The President, with assistance from the Manager of Finance & Rates, is responsible for presenting and recommending the budget to the Board of Directors for approval.

> It is the responsibility of the Board of Directors, on behalf of the shareholder, to approve the budget.

The budget is an important planning tool for OHL. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of department budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. OHL notes that these Budget Plans address both capital and operating requirements.

RATE BASE VARIANCE ANALYSIS:

The following Table 1 sets out OHL's rate base and working capital calculations for 2006 Board Approved and Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year, and the following variances:

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

Table 1

Description	2006 OEB Approved*	2006 Actual	Variance from 2006 OEB	2007 Actual Year	Variance from 2006 Actual	2008 Actual Year	Variance from 2007 Actual Year	2009 Bridge Year	Variance from 2008 Actual Year	2010 Test Year	Variance from 2009 Bridge Year
Gross Fixed Assets	24,862,719	26,983,585	2,120,866	28,016,813	1,033,228	29,276,036	1,259,223	30,979,862	1,703,826	32,914,799	1,934,937
Accumulated	(11,663,237)	(13,739,390)	(2,076,153)	(14,770,385)	(1,030,995)	(15,767,852)	(997,467)	(16,912,687)	(1,144,835)	(18,114,388)	(1,201,701)
Net Book Value	13,199,482	13,244,195	44,713	13,246,428	2,233	13,508,184	261,756	14,067,176	558,991	14,800,412	733,236
Average Net Book Value	13,199,482	13,121,369	(78,113)	13,245,312	123,942	13,377,306	131,995	13,787,680	410,374	14,433,794	646,114
Working Capital	18,196,017	20,047,040	1,851,023	21,017,501	970,462	20,480,378	(537,123)	22,288,633	1,808,254	22,435,528	146,895
Working Capital Allowance	2,729,402	3,007,056	277,653	3,152,625	145,569	3,072,057	(80,568)	3,343,295	271,238	3,365,329	22,034
Rate Base	15,928,885	16,128,425	199,540	16,397,937	269,512	16,449,363	51,426	17,130,975	681,612	17,799,123	668,148

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

The 2010 Revenue Requirement for OHL is $ 5,362,234 therefore OHL has calculated the materiality threshold on its rate base to be $50,000 for 2010 in accordance with the Filing Requirements (distributors with a distribution revenue requirement of less than or equal to $10 million).

OHL offers the following comments in respect of the relevant variances identified above. OHL also explains projects under the materiality where relevant.

2010 Test Year:

As shown in Table 1 above, the total rate base in the 2010 test year is forecast to be $17,799,123. Average net fixed assets accounts for $ 14,433,794 of this total. The allowance for working capital totals $3,365,329 and has been calculated as 15% of the sum of the cost of power and controllable expenses.

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

The total rate base is expected to be $668,148 higher in the 2010 Test Year than in the 2009 Bridge Year. This increase is shown in Table 1 above and is attributable primarily to an increase in average net fixed assets of $646,114. The increase in fixed assets along with the required detailed information for projects is discussed in detail by capital project in Exhibit 2, Tab 3, Schedule 2.

The working capital allowance increased by $22,034 from the 2009 Bridge Year. A detailed calculation of the working capital allowance for the 2010 Test Year can be found at Exhibit 2, Tab 4, Schedule 1.

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

The total rate base for the 2009 Bridge Year is expected to be $17,130,975, which represents an increase of $681,612 over the 2008 Actual year. This change results in part from an increase in average net assets of $410,374. This increase is primarily due to capital expenditures. The working capital allowance increased by $271,238 from 2008. A detailed calculation of the working capital allowance for the 2009 Bridge Year can be found at Exhibit 2, Tab 4, Schedule 1.

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

The rate base of $16,449,363 for 2008 Actual increased over 2007 Actual by $51,426. This increase is made up of a change in average net assets of $131,995 as a result of capital expenditures. Detailed information for these projects can be found in Exhibit 2, Tab 2, Schedule 3. The working capital allowance decreased by $(80,568).

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

The rate base of $16,397,937 for 2007 Actual increased over 2006 Actual by $269,512. This increase is made up of a change in average net assets of $123,942 as a result of capital expenditures. The working capital allowance increased by $145,569.

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

The rate base of $16,128,425 for 2006 Actual was higher than the 2006 Board Approved by $199,540. The difference reflects the fact that the 2006 Board Approved amounts were calculated as the average of the 2003 and 2004 actual amounts.

The variance between the 2006 Actual and the 2006 Board Approved included the difference between the 2004 actual and the 2006 Board Approved amounts as well as the 2005 normal investments.

CONTINUITY STATEMENTS:

Table 1
OHL
Fixed Asset Continuity Schedule
As at December 31, 2006

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	29,126	0		29,126	0	0	0	0	29,126
1806	Land Rights	23,805	6,056		29,861	4,705	1,194	0	5,899	23,962
1808	Buildings and Fixtures	15,296	0		15,296	15,296	0	0	15,296	0
1810	Leasehold Improvements	5,256	0		5,256	5,256	0	0	5,256	0
1815	Transformer Stn Equip-Normally Primary above 50kV	0	0		0	0	0	0	0	0
1820	Distribution Stn Equip-Normally Primary below 50kV	838,981	26,177		865,157	468,368	28,059	0	496,427	368,730
1825	Storage Battery Equipment	0	0		0	0	0	0	0	0
1830	Poles, Towers and Fixtures	3,872,701	58,319		3,931,020	2,217,850	139,772	0	2,357,622	1,573,398
1835	Overhead Conductors and Devices	3,020,754	237,931		3,258,685	1,440,975	110,920	0	1,551,895	1,706,790
1840	Underground Conduit	2,974,027	(139,267)		2,834,760	1,196,642	105,898	0	1,302,541	1,532,219
1845	Underground Conductors and Devices	2,991,839	331,720		3,323,559	1,385,399	126,984	0	1,512,383	1,811,176
1850	Line Transformers	6,334,506	437,817		6,772,323	2,691,318	250,396	0	2,941,715	3,830,608
1855	Services	2,018,756	78,764		2,097,520	1,081,249	89,293	0	1,170,542	926,978
1860	Meters	1,599,226	33,577		1,632,803	814,814	55,238	0	870,052	762,751
1865	Other Installations on Customer's Premises		0		0	0	0	0	0	0
1905	Land	144,400	0		144,400	0	0	0	0	144,400
1906	Land Rights	4,938	0		4,938	4,938	0	0	4,938	0
1908	Buildings and Fixtures	2,433,744	12,165	8,738	2,437,171	627,416	41,278	699	667,995	1,769,176
1910	Leasehold Improvements	0	0		0	0	0	0	0	0
1915	Office Furniture and Equipment	154,454	0	1,044	153,410	113,464	6,894	1,044	119,314	34,095
1920	Computer Equipment - Hardware	269,629	27,519	75,769	221,379	219,282	21,678	73,686	167,274	54,105
1925	Computer Software	270,109	85,691		355,800	205,055	40,551	0	245,606	110,194
1930	Transportation Equipment	781,820	316,548	146,212	952,156	645,644	93,053	146,212	592,486	359,670
1935	Stores Equipment	26,359	0		26,359	22,225	924	0	23,149	3,210
1940	Tools, Shop and Garage Equipment	177,581	2,206	42,295	137,492	150,294	8,733	41,986	117,042	20,450
1945	Measurement and Testing Equipment	13,920	0		13,920	7,723	1,392	0	9,115	4,804
1950	Power Operated Equipment	0	0		0	0	0	0	0	0
1955	Communication Equipment	23,157	0	3,834	19,323	15,622	1,007	3,834	12,795	6,528
1960	Miscellaneous Equipment	9,700	(0)	322	9,378	970	938	225	1,682	7,695
1970	Load Management Controls - Customer Premises	0	0		0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0		0	0	0	0	0	0
1980	System Supervisory Equipment	0	0		0	0	0	0	0	0
1985	Sentinel Lighting Rentals	9,804	0		9,804	9,171	178	0	9,349	455
1990	Other Tangible Property	0	0		0	0	0	0	0	0
1995	Contributions and Grants	(2,070,757)	(226,554)		(2,297,310)	(369,093)	(91,892)	0	(460,985)	(1,836,325)
	Totals:	**25,973,130**	**1,288,669**	**278,214**	**26,983,585**	**12,974,586**	**1,032,489**	**267,685**	**13,739,390**	**13,244,195**

Table 2
OHL
Fixed Asset Continuity Schedule
As at December 31, 2007

	Cost				Accumulated Depreciation				
Description	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
Land	29,126	0		29,126	0	0	0	0	29,126
Land Rights	29,861	3,956		33,817	5,899	1,353	0	7,252	26,565
Buildings and Fixtures	15,296	0		15,296	15,296	0	0	15,296	0
Leasehold Improvements	5,256	0	5,256	0	5,256	0	5,256	0	0
Transformer Stn Equip-Normally Primary above 50k	0	0		0	0	0	0	0	0
Distribution Stn Equip-Normally Primary below 50k	865,157	24,764		889,922	496,427	26,951	0	523,378	366,544
Storage Battery Equipment	0	0		0	0	0	0	0	0
Poles, Towers and Fixtures	3,931,020	84,105		4,015,125	2,357,622	140,947	0	2,498,570	1,516,556
Overhead Conductors and Devices	3,258,685	149,469		3,408,155	1,551,895	115,998	0	1,667,893	1,740,262
Underground Conduit	2,834,760	247,003		3,081,763	1,302,541	115,779	0	1,418,320	1,663,444
Underground Conductors and Devices	3,323,559	230,686		3,554,245	1,512,383	136,211	0	1,648,594	1,905,650
Line Transformers	6,772,323	352,352		7,124,675	2,941,715	264,491	0	3,206,206	3,918,469
Services	2,097,520	102,075		2,199,595	1,170,542	93,275	0	1,263,817	935,777
Meters	1,632,803	135,383		1,768,186	870,052	60,095	0	930,147	838,039
Other Installations on Customer's Premises	0	0		0	0	0	0	0	0
Land	144,400	0		144,400	0	0	0	0	144,400
Land Rights	4,938	0		4,938	4,938	0	0	4,938	0
Buildings and Fixtures	2,437,171	168,051		2,605,221	667,995	44,290	0	712,284	1,892,937
Leasehold Improvements	0	0		0	0	0	0	0	0
Office Furniture and Equipment	153,410	34,559	810	187,159	119,314	10,174	567	128,922	58,237
Computer Equipment - Hardware	221,379	14,090	17,554	217,915	167,274	29,922	17,554	179,642	38,273
Computer Software	355,800	30,546	3,526	382,819	245,606	44,874	3,526	286,953	95,866
Transportation Equipment	952,156	31,645	26,336	957,465	592,486	99,382	26,336	665,533	291,932
Stores Equipment	26,359	5,668		32,027	23,149	1,917	0	25,067	6,961
Tools, Shop and Garage Equipment	137,492	4,799	669	141,623	117,042	9,043	669	125,416	16,207
Measurement and Testing Equipment	13,920	1,399		15,319	9,115	1,532	0	10,647	4,672
Power Operated Equipment	0	0		0	0	0	0	0	0
Communication Equipment	19,323	0		19,323	12,795	1,007	0	13,803	5,520
Miscellaneous Equipment	9,378	2,131	443	11,066	1,682	1,107	310	2,479	8,587
Load Management Controls - Customer Premises	0	0		0	0	0	0	0	0
Load Management Controls - Utility Premises	0	0		0	0	0	0	0	0
System Supervisory Equipment	0	0		0	0	0	0	0	0
Sentinel Lighting Rentals	9,804	0		9,804	9,349	152	0	9,501	303
Other Tangible Property	0	0		0	0	0	0	0	0
Contributions and Grants	(2,297,310)	(534,860)		(2,832,170)	(460,985)	(113,287)	0	(574,272)	(2,257,898)
Totals:	**26,983,585**	**1,087,822**	**54,594**	**28,016,813**	**13,739,390**	**1,085,213**	**54,218**	**14,770,385**	**13,246,428**

Table 2
OHL
Fixed Asset Continuity Schedule
As at December 31, 2008

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	29,126	0		29,126	0	0	0	0	29,126
CEC	1806	Land Rights	33,817	0		33,817	7,252	1,353	0	8,605	25,212
1	1808	Buildings and Fixtures	15,296	0		15,296	15,296	0	0	15,296	0
	1810	Leasehold Improvements	0	0		0	0	0	0	0	0
	1815	Transformer Stn Equip-Normally Primary above 50k	0	0		0	0	0	0	0	0
47	1820	Distribution Stn Equip-Normally Primary below 50kV	889,922	12,969		902,891	523,378	24,146	0	547,524	355,367
	1825	Storage Battery Equipment	0	0		0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	4,015,125	112,513		4,127,638	2,498,570	140,774	0	2,639,343	1,488,295
47	1835	Overhead Conductors and Devices	3,408,155	161,649		3,569,804	1,667,893	117,364	0	1,785,256	1,784,548
47	1840	Underground Conduit	3,081,763	317,537		3,399,300	1,418,320	122,129	0	1,540,449	1,858,851
47	1845	Underground Conductors and Devices	3,554,245	121,483		3,675,728	1,648,594	138,222	0	1,786,816	1,888,912
47	1850	Line Transformers	7,124,675	586,829		7,711,503	3,206,206	276,227	0	3,482,433	4,229,070
47	1855	Services	2,199,595	31,435		2,231,030	1,263,817	93,675	0	1,357,492	873,538
47	1860	Meters	1,768,186	35,731		1,803,916	930,147	60,810	0	990,957	812,959
	1865	Other Installations on Customer's Premises	0	0		0	0	0	0	0	0
N/A	1905	Land	144,400	0		144,400	0	0	0	0	144,400
CEC	1906	Land Rights	4,938	0		4,938	4,938	0	0	4,938	0
1	1908	Buildings and Fixtures	2,605,221	109,490	2,787	2,711,924	712,284	45,503	1,059	756,729	1,955,196
	1910	Leasehold Improvements	0	0		0	0	0	0	0	0
8	1915	Office Furniture and Equipment	187,159	2,632	4,369	185,422	128,922	9,588	4,369	134,141	51,281
50	1920	Computer Equipment - Hardware	217,915	8,778	32,884	193,809	179,642	13,833	31,127	162,348	31,461
12	1925	Computer Software	382,819	50,753		433,572	286,953	43,972	0	330,925	102,647
10	1930	Transportation Equipment	957,465	0		957,465	665,533	68,388	0	733,921	223,544
10	1935	Stores Equipment	32,027	910	3,112	29,825	25,067	992	3,390	22,668	7,157
8	1940	Tools, Shop and Garage Equipment	141,623	4,235		145,858	125,416	5,985	0	131,401	14,457
	1945	Measurement and Testing Equipment	15,319	0		15,319	10,647	1,532	0	12,179	3,140
	1950	Power Operated Equipment	0	0		0	0	0	0	0	0
10	1955	Communication Equipment	19,323	0		19,323	13,803	1,007	0	14,810	4,513
8	1960	Miscellaneous Equipment	11,066	11,876	2,395	20,547	2,479	1,461	1,677	2,264	18,284
	1970	Load Management Controls - Customer Premises	0	0		0	0	0	0	0	0
	1975	Load Management Controls - Utility Premises	0	0		0	0	0	0	0	0
	1980	System Supervisory Equipment	0	0		0	0	0	0	0	0
	1985	Sentinel Lighting Rentals	9,804	0	9,804	0	9,501	166	9,667	0	0
	1990	Other Tangible Property	0	0		0	0	0	0	0	0
47	1995	Contributions and Grants	(2,832,170)	(254,245)		(3,086,415)	(574,272)	(118,372)	0	(692,644)	(2,393,772)
		Totals:	**28,016,813**	**1,314,574**	**55,351**	**29,276,036**	**14,770,385**	**1,048,755**	**51,288**	**15,767,852**	**13,508,184**

Table 3
OHL
Fixed Asset Continuity Schedule
As at December 31, 2009

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	29,126	0		29,126	0	0		0	29,126
1806	Land Rights	33,817	0		33,817	8,605	1,353		9,957	23,860
1808	Buildings and Fixtures	15,296	0		15,296	15,296	0		15,296	0
1810	Leasehold Improvements	0	0		0	0	0		0	0
1815	Transformer Stn Equip-Normally Primary above 50kV	0	0		0	0	0		0	0
1820	Distribution Stn Equip-Normally Primary below 50kV	902,891	7,382		910,274	547,524	25,113		572,637	337,637
1825	Storage Battery Equipment	0	0		0	0	0		0	0
1830	Poles, Towers and Fixtures	4,127,638	146,908		4,274,547	2,639,343	146,750		2,786,094	1,488,453
1835	Overhead Conductors and Devices	3,569,804	148,936		3,718,740	1,785,256	125,349		1,910,605	1,808,135
1840	Underground Conduit	3,399,300	303,293		3,702,592	1,540,449	133,452		1,673,901	2,028,691
1845	Underground Conductors and Devices	3,675,728	370,611		4,046,339	1,786,816	148,153		1,934,970	2,111,369
1850	Line Transformers	7,711,503	650,758		8,362,261	3,482,433	314,483		3,796,916	4,565,345
1855	Services	2,231,030	107,871		2,338,901	1,357,492	92,132		1,449,624	889,277
1860	Meters	1,803,916	15,630		1,819,546	990,957	62,179		1,053,136	766,410
1865	Other Installations on Customer's Premises	0	0		0	0	0		0	0
1905	Land	144,400	0		144,400	0	0		0	144,400
1906	Land Rights	4,938	0		4,938	4,938	0		4,938	0
1908	Buildings and Fixtures	2,711,924	17,000		2,728,924	756,729	46,961		803,689	1,925,235
1910	Leasehold Improvements	0	0		0	0	0		0	0
1915	Office Furniture and Equipment	185,422	0		185,422	134,141	9,295		143,437	41,985
1920	Computer Equipment - Hardware	193,809	22,100		215,909	162,348	18,616		180,964	34,945
1925	Computer Software	433,572	216,144		649,716	330,925	81,999		412,924	236,792
1930	Transportation Equipment	957,465	130,000		1,087,465	733,921	69,105		803,026	284,439
1935	Stores Equipment	29,825	5,000		34,825	22,668	1,678		24,347	10,478
1940	Tools, Shop and Garage Equipment	145,858	5,000		150,858	131,401	4,427		135,828	15,030
1945	Measurement and Testing Equipment	15,319	1,000		16,319	12,179	1,358		13,537	2,781
1950	Power Operated Equipment	0	0		0	0	0		0	0
1955	Communication Equipment	19,323	0		19,323	14,810	1,007		15,818	3,506
1960	Miscellaneous Equipment	20,547	14,755		35,302	2,264	3,434		5,697	29,605
1970	Load Management Controls - Customer Premises	0	0		0	0	0		0	0
1975	Load Management Controls - Utility Premises	0	0		0	0	0		0	0
1980	System Supervisory Equipment	0	0		0	0	0		0	0
1985	Sentinel Lighting Rentals	0	0		0	0	0		0	0
1990	Other Tangible Property	0	0		0	0	0		0	0
1995	Contributions and Grants	(3,086,415)	(458,562)		(3,544,977)	(692,644)	(142,011)		(834,655)	(2,710,323)
	Totals:	**29,276,036**	**1,703,826**	**0**	**30,979,862**	**15,767,852**	**1,144,835**	**0**	**16,912,687**	**14,067,176**

Table 4
OHL
Fixed Asset Continuity Schedule
As at December 31, 2010

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
										0	
N/A	1805	Land	29,126	0		29,126	0	0		0	29,126
CEC	1806	Land Rights	33,817	0		33,817	9,957	1,353		11,310	22,507
1	1808	Buildings and Fixtures	15,296	0		15,296	15,296	0		15,296	0
	1810	Leasehold Improvements	0	0		0	0	0		0	0
	1815	Transformer Stn Equip-Normally Primary above 50kV	0	0		0	0	0		0	0
47	1820	Distribution Stn Equip-Normally Primary below 50kV	910,274	123,578		1,033,851	572,637	27,172		599,809	434,042
	1825	Storage Battery Equipment	0	0		0	0	0		0	0
47	1830	Poles, Towers and Fixtures	4,274,547	41,939		4,316,486	2,786,094	147,589		2,933,683	1,382,803
47	1835	Overhead Conductors and Devices	3,718,740	255,384		3,974,125	1,910,605	130,457		2,041,062	1,933,063
47	1840	Underground Conduit	3,702,592	233,544		3,936,136	1,673,901	138,123		1,812,024	2,124,112
47	1845	Underground Conductors and Devices	4,046,339	347,990		4,394,329	1,934,970	155,113		2,090,083	2,304,246
47	1850	Line Transformers	8,362,261	699,225		9,061,486	3,796,916	328,468		4,125,383	4,936,103
47	1855	Services	2,338,901	110,559		2,449,460	1,449,624	94,343		1,543,967	905,493
47	1860	Meters	1,819,546	90,971		1,910,517	1,053,136	63,999		1,117,135	793,382
	1865	Other Installations on Customer's Premises	0	0		0	0	0		0	0
N/A	1905	Land	144,400	0		144,400	0	0		0	144,400
CEC	1906	Land Rights	4,938	0		4,938	4,938	0		4,938	0
1	1908	Buildings and Fixtures	2,728,924	10,000		2,738,924	803,689	47,061		850,750	1,888,174
	1910	Leasehold Improvements	0	0		0	0	0		0	0
8	1915	Office Furniture and Equipment	185,422	25,000		210,422	143,437	10,545		153,982	56,440
50	1920	Computer Equipment - Hardware	215,909	57,800		273,709	180,964	24,396		205,360	68,348
12	1925	Computer Software	649,716	118,780		768,496	412,924	93,877		506,801	261,695
10	1930	Transportation Equipment	1,087,465	65,000		1,152,465	803,026	73,168		876,194	276,271
10	1935	Stores Equipment	34,825	0		34,825	24,347	1,678		26,025	8,800
8	1940	Tools, Shop and Garage Equipment	150,858	5,000		155,858	135,828	4,677		140,505	15,352
8	1945	Measurement and Testing Equipment	16,319	1,000		17,319	13,537	1,408		14,946	2,373
	1950	Power Operated Equipment	0	0		0	0	0		0	0
10	1955	Communication Equipment	19,323	0		19,323	15,818	1,007		16,825	2,498
8	1960	Miscellaneous Equipment	35,302	0		35,302	5,697	3,434		9,131	26,171
	1970	Load Management Controls - Customer Premises	0	22,000		22,000	0	1,100		1,100	20,900
	1975	Load Management Controls - Utility Premises	0	0		0	0	0		0	0
8	1980	System Supervisory Equipment	0	15,000		15,000	0	500		500	14,500
	1985	Sentinel Lighting Rentals	0	0		0	0	0		0	0
	1990	Other Tangible Property	0	0		0	0	0		0	0
47	1995	Contributions and Grants	(3,544,977)	(287,833)		(3,832,810)	(834,655)	(147,768)		(982,422)	(2,850,388)
		Total before Work in Process	**30,979,862**	**1,934,937**	**0**	**32,914,799**	**16,912,687**	**1,201,701**	**0**	**18,114,388**	**14,800,412**
WIP	0	Work in Process	0			0	0			0	0
		Totals:	**30,979,862**	**1,934,937**	**0**	**32,914,799**	**16,912,687**	**1,201,701**	**0**	**18,114,388**	**14,800,412**

GROSS ASSETS TABLE:

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Bridge ($)	Variance from 2008 Actual	2010 Test ($)	Variance from 2009 Bridge
Land and Buildings											
1805-Land	29,126	29,126		29,126		29,126		29,126		29,126	
1806-Land Rights	23,208	29,861	6,652	33,817	3,956	33,817		33,817		33,817	
1808-Buildings and Fixtures	15,296	15,296		15,296		15,296		15,296		15,296	
1905-Land	144,400	144,400		144,400		144,400		144,400		144,400	
1906-Land Rights	4,938	4,938		4,938		4,938		4,938		4,938	
1810-Leasehold Improvements	5,256	5,256			(5,256)						
Sub-Total-Land and Buildings	222,225	228,878	6,652	227,577	(1,300)	227,577		227,577		227,577	
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	733,750	865,157	131,407	889,922	24,764	902,891	12,969	910,274	7,382	1,033,851	123,578
Sub-Total-DS	733,750	865,157	131,407	889,922	24,764	902,891	12,969	910,274	7,382	1,033,851	123,578
Poles and Wires											
1830-Poles, Towers and Fixtures	3,749,091	3,931,020	181,928	4,015,125	84,105	4,127,638	112,513	4,274,547	146,908	4,316,486	41,939
1835-Overhead Conductors and Devices	2,872,733	3,258,685	385,953	3,408,155	149,469	3,569,804	161,649	3,718,740	148,936	3,974,125	255,384
1840-Underground Conduit	2,895,012	2,834,760	(60,253)	3,081,763	247,003	3,399,300	317,537	3,702,592	303,293	3,936,136	233,544
1845-Underground Conductors and Devices	2,849,554	3,323,559	474,005	3,554,245	230,686	3,675,728	121,483	4,046,339	370,611	4,394,329	347,990
Sub-Total-Poles and Wires	12,366,390	13,348,023	981,633	14,059,288	711,264	14,772,470	713,182	15,742,218	969,748	16,621,075	878,857
Line Transformers											
1850-Line Transformers	5,778,983	6,772,323	993,340	7,124,675	352,352	7,711,503	586,829	8,362,261	650,758	9,061,486	699,225
Sub-Total-Line Transformers	5,778,983	6,772,323	993,340	7,124,675	352,352	7,711,503	586,829	8,362,261	650,758	9,061,486	699,225
Services and Meters											
1855-Services	1,985,333	2,097,520	112,187	2,199,595	102,075	2,231,030	31,435	2,338,901	107,871	2,449,460	110,559
1860-Meters	1,553,483	1,632,803	79,320	1,768,186	135,383	1,803,916	35,731	1,819,546	15,630	1,910,517	90,971
Sub-Total-Services and Meters	3,538,816	3,730,322	191,507	3,967,781	237,458	4,034,946	67,166	4,158,447	123,501	4,359,977	201,530
General Plant											
1908-Buildings and Fixtures	2,420,800	2,437,171	16,371	2,605,221	168,051	2,711,924	106,703	2,728,924	17,000	2,738,924	10,000
1910-Leasehold Improvements											
Sub-Total-General Plant	2,420,800	2,437,171	16,371	2,605,221	168,051	2,711,924	106,703	2,728,924	17,000	2,738,924	10,000
IT Assets											
1920-Computer Equipment - Hardware	249,741	221,379	(28,362)	217,915	(3,464)	193,809	(24,106)	215,909	22,100	273,709	57,800
1925-Computer Software	221,340	355,800	134,460	382,819	27,020	433,572	50,753	649,716	216,144	768,496	118,780
Sub-Total-IT Assets	471,081	577,179	106,098	600,734	23,555	627,381	26,647	865,625	238,244	1,042,205	176,580
Equipment											
1915-Office Furniture and Equipment	163,789	153,410	(10,379)	187,159	33,749	185,422	(1,737)	185,422		210,422	25,000
1930-Transportation Equipment	758,070	952,156	194,086	957,465	5,309	957,465		1,087,465	130,000	1,152,465	65,000
1935-Stores Equipment	29,048	26,359	(2,689)	32,027	5,668	29,825	(2,202)	34,825	5,000	34,825	
1940-Tools, Shop and Garage Equipment	177,705	137,492	(40,213)	141,623	4,131	145,858	4,235	150,858	5,000	155,858	5,000
1945-Measurement and Testing Equipment	13,920	13,920		15,319	1,399	15,319		16,319	1,000	17,319	1,000
1955-Communication Equipment	27,081	19,323	(7,758)	19,323		19,323		19,323		19,323	
1960-Miscellaneous Equipment	7,649	9,378	1,728	11,066	1,689	20,547	9,481	35,302	14,755	35,302	
Sub-Total-Equipment	1,177,263	1,312,038	134,775	1,363,982	51,944	1,373,759	9,776	1,529,513	155,755	1,625,513	96,000
Other Distribution Assets											
1970-Load Management Controls - Customer										22,000	22,000
1980-System Supervisory Equipment										15,000	15,000
1995-Contributions and Grants - Credit	(1,939,608)	(2,297,310)	(357,702)	(2,832,170)	(534,860)	(3,086,415)	(254,245)	(3,544,977)	(458,562)	(3,832,810)	(287,833)
Sub-Total-Other Distribution Assets	(1,939,608)	(2,287,507)	(347,898)	(2,822,366)	(534,860)	(3,086,415)	(264,049)	(3,544,977)	(458,562)	(3,795,810)	(250,833)
GROSS ASSET TOTAL	24,769,700	26,983,585	2,213,885	28,016,813	1,033,228	29,276,036	1,259,223	30,979,862	1,703,826	32,914,799	1,934,937

Note: 2006 Board Approved amount for gross asset total is $24,862,719, including CDM assets (Account 1565) of $93,019. CDM assets are not included in the 2010 Test Year rate base calculation; accordingly, Account 1565 is omitted from this table.

VARIANCE ANALYSIS ON GROSS ASSETS:

The Gross Asset Variance analysis for those variances highlighted in Table 1 of Exhibit 2, Tab 2, Schedule 2 is provided as follows.

2005 and 2006 Capital Expenditures:

2005 Capital Expenditures

Category	In Service Date	Project Description	Total Project	Account 1806	Account 1820	Account 1830	Account 1835	Account 1840	Account 1845	Account 1850	Account 1855	Account 1860	Account 1995
Cust Demand	2005	5 New Services	59,149	-	-	-	1,714	-	9,820	47,615	-	-	
Cust Demand	2005	Westside Market Village	121,107	-	-	-	-	-	25,451	95,656	-	-	
Renewal	2005	27.6-Broadway and Faulkner	112,990	-	-	22,977	33,581	-	-	50,902	5,530	-	
Renewal	2005	51 Centennial Pole Line Upgrade	42,877	-	-	12,217	8,799	-	-	21,861	-	-	
Renewal	2005	Rolling Hills	10,394	-	-	-	-	-	10,394	-	-	-	
Renewal	2005	Cable terminations/arrestors	7,297	-	7,297	-	-	-	-	-	-	-	
Renewal	2005	Misc Pole Replacement	16,340	-	-	1,700	4,538	-	-	10,102	-	-	
Renewal	2005	Misc Underground Projects	28,718	-	-	-	-	8,173	4,896	15,650	-	-	
Substation	2005	MS#1 Removal Project	309,727	-	-	52,039	44,914	25,355	43,641	131,095	12,682	-	
Regulatory	2005	Browns Farm	76,650	-	-	-	-	22,502	-	54,148	-	-	
Inventory	2005	Transformer Inventory	14,462	-	-	-	-	-	-	14,462	-	-	
Land Rights	2005	Land Rights	150	150	-	-	-	-	-	-	-	-	
Metering	2005	Hydro One Exit Fees	10,400	-	10,400	-	-	-	-	-	-	-	
Metering	2005	Meter Installations	28,865	-	-	-	-	-	-	-	-	28,865	
Cont. Capital	2005	Total Contributed Capital	(112,889)										(112,889)
Total			726,236	150	17,697	88,932	93,547	56,030	94,203	441,490	18,212	28,865	(112,889)

Category	In Service Date	Project Description	Total Project	Account 1905	Account 1915	Account 1920	Account 1925	Account 1930	Account 1935	Account 1940	Account 1945	Account 1955	Account 1960
Facilities	2005	General Plant	7,193	7,193	-	-	-	-	-	-	-	-	-
Equipment	2005	Office Equipment	8,467	-	8,467	-	-	-	-	-	-	-	-
Hardware	2005	Misc Computer Hardware	18,359	-	-	18,359	-	-	-	-	-	-	-
Software	2005	Misc Computer Software	19,418	-	-	-	19,418	-	-	-	-	-	-
Vehicles	2005	Pickup Truck Replacement	34,789	-	-	-	-	34,789	-	-	-	-	-
Tools & Equip	2005	Replace Major Tools	5,714	-	-	-	-	-	-	5,714	-	-	-
Tools & Equip	2005	3 New Truck Radios	1,868	-	-	-	-	-	-	-	-	1,868	-
Tools & Equip	2005	Misc Equipment	2,050	-	-	-	-	-	-	-	-	-	2,050
		Total	97,859	7,193	8,467	18,359	19,418	34,789	-	5,714	-	1,868	2,050
		Total Capital Expenditures	824,095.05										

Category	In Service Date	Project Description	Total Project	Account 1806	Account 1820	Account 1830	Account 1835	Account 1840	Account 1845	Account 1850	Account 1855	Account 1860	Account 1995
Cust Demand	2006	B04-B Line Pole Line	111,576	-	-	51,957	59,619	-	-	-	-	-	
Cust Demand	2007	B03-Veterans Way	99,162	-	-	91,191	7,971	-	-	-	-	-	
Cust Demand	2006	Country Meadows Infill	62,090	-	-	-	-	22,016	11,341	14,438	14,296	-	
Cust Demand	2006	9 Misc New Services	185,786	-	-	-	-	-	39,512	146,274	-	-	
Renewal	2007	B01-Burbank Rebuild	124,647	-	-	-	-	87,384	9,389	27,874	-	-	
Renewal	2006	Robb Blvd Pole Replacement	9,439	-	-	4,811	4,628	-	-	-	-	-	
Renewal	2006	Misc Pole Replacement	34,776	-	-	19,039	11,351	-	-	4,386	-	-	
Renewal	2006	Misc Underground Projects	29,595	-	-	-	-	6,057	11,244	12,294	-	-	
Renewal	2006	Misc Transformer Replace	8,538	-	-	-	-	-	-	8,538	-	-	
Renewal	2006	Grand Valley	3,766	-	-	(150,073)	115,141	(257,190)	244,330	-	51,195	362	
Substation	2006	DS#1 Removal Project	107,061	-	-	24,274	24,246	2,467	2,832	39,970	13,273	-	
Substation	2006	Substation Betterment	26,177	-	26,177	-	-	-	-	-	-	-	
Regulatory	2006	Load Transfers	52,681	-	-	17,119	14,974	-	8,981	11,607	-	-	
Regulatory	2007	Browns Farm	23,055	-	-	-	-	-	4,091	18,964	-	-	
Inventory	2006	Transformer Inventory	153,472	-	-	-	-	-	-	153,472	-	-	
Land Rights	2006	Land Rights	6,056	6,056	-	-	-	-	-	-	-	-	
Metering	2006	Meter Installations	33,215	-	-	-	-	-	-	-	-	33,215	
	2006	Total Contributed Capital	(226,554)										(226,554)
Total			844,540	6,056	26,177	58,319	237,931	(139,267)	331,720	437,817	78,764	33,577	(226,554)
		Variance from 2006 EDR											

Category	In Service Date	Project Description	Total Project	Account 1905	Account 1915	Account 1920	Account 1925	Account 1930	Account 1935	Account 1940	Account 1945	Account 1955	Account 1960
Facilities	2006	General Plant	12,165	12,165	-	-	-	-	-	-	-	-	-
Hardware	2006	Misc Computer Hardware	26,266	-	-	26,266	-	-	-	-	-	-	-
Software	2006	Misc Computer Software	7,243	-	-	-	7,243	-	-	-	-	-	-
Software	2006	Job Cost/Payroll Modules	53,394				53,394						
Software	2006	Grand Valley-CIS software	26,307	-	-	1,253	25,054	-	-	-	-	-	-
Vehicles	2006	Double Bucket Truck Replacemer	316,548	-	-	-	-	316,548	-	-	-	-	-
Tools & Equip	2006	Replace Tools & Equipment	2,206	-	-	-	-	-	-	2,206	-	-	-
Total			444,129	12,165	-	27,519	85,691	316,548	-	2,206	-	-	-
		Total Capital Expenditures	1,288,669										

The 2006 Board Approved amounts for each account were calculated as the average of the 2003 and 2004 actual amounts in accordance with the 2006 rate model. As such the amount for the 2006 Actual includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 normal investments. The above tables set out the 2005 and 2006 capital expenditures by account. The capital expenditures for 2005 amount to $824,095 and 2006 amount to $ 1,288,669. The total capital expenditures are $2,112,764. The 2006 EDR approved amount is $2,213,885. The difference between the2006 EDR and the 2005/2006 total amounted to $101,121.

CUSTOMER DEMAND

2005 Project: Westside market

Cost: $121,107 1845-$25,451 1850-$95,656

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: Plaza development on the west side of Town. The project consisted of underground primary and to supply and install 3 PME units and one three phase transformer. Contributed capital was received for this project as per the OHL's Conditions of Service.

2006 Project: B Line Extension Completion in 2007

Cost: $111,576 1830-51,957 1835-$59,619

Need: The B-Line project was built for 2 new subdivisions that were to be connected in 2007.

Scope: This project consisted of expanding an existing pole line of approximately 20 poles and 20 spans of conductor that were installed in the south-west boundary. The cost for this project was included in the economic evaluation performed in 2007 for Credit Springs and Wilside Phase 4 to determine the applicable contributed capital.

2006 Project: Veterans Way Expansion Completion in 2007

Cost: $99,162 1830-$91,191 1835-$7,971

Need: In preparation and anticipation of servicing Humber College site, a new Town well and pumping station, future subdivisions and to deal with some of the load transfer issues.

Scope: A pole line extension was built consisting of approximately 30 poles, hardware and conductors. Due to the economic downturn most of these projects are on hold. The town well has been installed and contributed capital was received. When we receive the new service connection requests contributed capital will apply.

2006 Project: Country Meadows Infill Economic Evaluation

Cost: $62,090 1840-$22,016 1845-11,341 1850-$14,438
1855-$14,296

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: Recording of the distribution and transformation of the subdivision development through the economic evaluation model to determine the contributed capital portion of the project.

RENEWAL

2005 Project: Broadway & Faulkner

Cost: $112,990 1830-$22,977 1835-$33,581 1850-$50,902
1855-$5,530

Need: To replace old existing pole lines in need of replacement due to age, deterioration and inadequate clearances and could not be deferred due to reliability issues. This is part OHL's long term plan to stay consistent with past practice and policy that all renewals are constructed to 27.6 kV standards and are converted from our 4 kV system.

Scope: The replacement of 6 poles between First & Faulkner Streets. This area was converted thus requiring the replacement of existing transformers and to changeover conductor to the new poles. Installation of poles, conductor and transformer to 27.6 kV standard.

2005 Project: Centennial Pole Line Upgrade

Cost: $42,877	1830-$12,217	1835-$8,799	1850-$21,861

Need: We have been gradually upgrading an existing pole line in an older industrial area due to age, deterioration and inadequate clearances. Improper framing standards were used a number of years ago when the 27.6 kV circuit was installed in this area. With the expected growth of new commercial services in this area, OHL upgraded the line to provide adequate clearances for safety and increased reliability.

Scope: The replacement of approximate 2 poles and changeover of the conductor and converted transformer to the 27.6 kV standard.

2006 Project: Burbank Rebuild Completion 2007

Cost: $124,647	1840-$87,384	1845-$9,389	1850-$27,874

Need: The cable in this area is over 30 years of age and has been damaged in the past few years by a number of faults. To improve reliability it was determined that the cable is nearing end of life condition and therefore an extensive rebuild was warranted. We expected by performing this work it would help to decrease our callouts/outages thus decreasing our O&M expenses.

Scope: Consisted of the replacement of primary cable and transformers converting to the 27.6 kV circuit. Due to complexity, directional boring was required and installation of ductwork. The remainder of this project was completed in 2007 due to the size and cost so OHL scheduled the project over a two-year period.

2006 Project: Grand Valley GL Account Reclassification

Cost: $3,766 1830-$(150,073) 1835-$115,141 1840-$(257,190)
1855-$51,195

Explanation: Grand Valley did not reclassify their general ledger accounts according to the definitions of accounts in the Accounts Procedures handbook. For cost allocation purposes the general ledger accounts were set up properly.

SUBSTATION

2005 Project: DS 1 Substation Removal

Cost: $309,727 1830-$52,039 1835-$44,914 1840-$25,355
1845-$43,641 1850-$131,095 1855-$12,682

Need: Conversion plan to eliminate this substation that is over 55 years old. Our DS #1 substation consists of 3-1 MVA transformers that have a manufacture date of 1954. Testing has been completed each year and various results indicated that these transformers are starting to deteriorate and approaching a near end of life condition. Due to new development in our downtown core a 27.6 kV circuit was installed a number of years ago. It was determined by OHL that it would be more prudent to continue with the conversion in this area rather than completing expensive upgrades to the old 4 kV station. We are aiming to have this station removed by 2010.

Scope: In this segment of the project we converted parts of Mill, Armstrong and John Streets that are fed from that distribution station. This work consisted of replacing a number of poles because of age, deterioration and improper clearances. Replacement of transformers and primary cable at were replaced due to the improper voltages to allow for the conversion from 4 kV to 27.6 kV.

2006 Project: DS 1 Substation Removal

Cost: $107,061	1830-$24,274	1835-$24,246	1840-$2,467
	1845-$2,832	1850-$39,970	1855-$13,273

Need: Conversion plan to eliminate this substation that is over 55 years old. Our DS #1 substation consists of 3-1 MVA transformers that have a manufacture date of 1954. Testing has been completed each year and various results indicated that these transformers are starting to deteriorate and approaching a near end of life condition. Due new development in our downtown core a 27.6 kV circuit was installed a number of years ago. It was determined by OHL that it would be more prudent to continue with the conversion in this area rather than completing expensive upgrades to the old 4 kV station. This distribution station will be out of service in 2009 and scheduled to be removed in 2010.

Scope: In this segment of the project we converted parts of Church, Sarah, Henry and William Streets that are fed from that distribution station. This work consisted of identifying poles that required replacing due to age, deterioration and improper clearances. Replacement of transformers and primary cable at were replaced due to the improper voltages to allow for the conversion from 4 kV to 27.6 kV.

REGULATORY

2005 Project: Browns Farm-Completion 2005 to 2007

Cost: $76,650	1840-$22,502	1850-$54,148

Need: The Town of Orangeville was installing a new water/sewer pipeline and resurfacing the road at Diane and Brenda Streets in a 40 year old area of town. OHL thought it prudent to install underground conduit in order to split the cost of trenching 50% and take the opportunity to replace ageing transformers so that we would not be digging up the area when we convert from 4 kV to 27.6 kV.

Scope: There was a number of existing transformer vaults that were changed due to age, proximity to curbs and sidewalks and had to be replaced or relocated.

2006 Project: Browns Farm -Completion 2005 to 2007

Cost: $23,055 1845-$4,091 1850-$18,964

Need: The Town of Orangeville was performing a complete civil engineering upgrade in this area. OHL thought it prudent to install underground conduit in order to split the cost of trenching 50% and take the opportunity to replace ageing transformers the so that we would not be digging up the area when we convert from 4 kV to 27.6 kV.

Scope: Continuation of the project started in 2005 with the installation of transformers and primary cable.

2006 Project: Load Transfers

Cost: $52,681 1830-$17,119 1835-$14,974 1845-$8,981
1850-$11,607

Need: To eliminate the load transfers from Hydro One per Section 6.5.3 the Distribution System code for the effective date of January 31, 2009.

Scope: To remove customers serviced by Hydro One at C Line and Townline, OHL installed 3 additional spans, poles, conductor and transformers to service some residential customers and also a transformer bank to provide servicing to the town well.

Transformer Inventory

In 2006, quite a number of customer demand projects were scheduled for 2007. To be prepared for these projects we received inventory in 2006 of transformers amounting to $153,472. The transformers need to be ordered 6 to 8 months prior to the scheduled installation.

GENERAL PLANT

2006 Project: Implement Job Cost and New Payroll Modules

Cost: $53,394 1925-$53,394

Need: OHL did not have a work order tracking method in place. We used the general ledger as a means to track the cost of a job but it did not effectively give us a proper breakdown of the jobs. The payroll was on another 3rd party DOS-based software that was outdated.

Scope: Upgrade Great Plains, set up job cost and payroll system with time-tracker.

2006 Project: Double Bucket Truck

Cost: $316,548 1930-$316,548

Need: The maintenance costs were on-going and far too costly on the 1989 double bucket truck. OHL's decision to replace our fleet is based on age of service which is 12 years on a large vehicle, past repair costs and safety related items.

Scope: Obtained 3 quotes for the specifications required and chose the lowest bidder.

2007 Actual Capital Expenditures:

2007 Capital Expenditures

Category	In Service Date	Project Desciption	Total Project	Account 1806	Account 1820	Account 1830	Account 1835	Account 1840	Account 1845	Account 1850	Account 1855	Account 1860	Account 1995
Cust Demand	2007	C01-Scotia Bank	51,392	-	-	-	-	-	5,798	45,594	-	-	(51,392)
Cust Demand	2007	B03-Veterans Way	132,841	-	-	20,991	91,028	-	-	20,822	-	-	-
Cust Demand	2007	Willside pumping station	50,343	-	-	-	-	-	37,417	12,925	-	-	-
Cust Demand	2007	Wilside Phase 4	173,787	-	-	-	-	60,862	32,441	40,964	39,521	-	(168,330)
Cust Demand	2007	Credit Springs	227,208	-	-	-	-	65,735	43,424	65,512	52,536	-	(209,397)
Cust Demand	2007	4 New Services	50,231	-	-	-	-	-	20,589	29,641	-	-	(52,630)
Cust Demand	2008	B04-B Line Pole Line	8,401	-	-	4,729	-	-	-	3,672	-	-	-
Security	2008	B06-Riddell Rd	46,567	-	-	23,448	23,119	-	-	-	-	-	-
Renewal	2007	B01-Burbank Cres	125,546	-	-	-	-	-	28,754	96,792	-	-	-
Renewal	2007	B07-80 Centennial Rd	53,499	-	-	-	-	7,177	13,352	32,971	-	-	-
Renewal	2007	William St Conversion	23,212	-	-	2,058	2,365	10,355	7,252	1,183	-	-	-
Renewal	2007	70 Mill St-Relocate Pole	16,921	-	-	2,058	2,389	-	-	11,672	803	-	
Renewal	2007	Century and C-Line	14,924	-	-	-	5,296	-	9,627	-	-	-	
Renewal	2007	Pheasant Court	41,077	-	-	-	-	-	8,502	32,575	-	-	-
Renewal	2007	Misc Transformer Replacemt	54,890	-	-	-	-	-	-	54,890	-	-	
Renewal	2007	Misc Pole Replacement	25,686	-	-	16,103	8,332	-	-	1,251	-	-	-
Renewal	2007	Misc Underground Projects	22,991	-	-	-	-	1,361	16,466	4,429	736	-	-
Renewal	2007	Betterments to Substations	24,764	-	24,764	-	-	-	-	-	-	-	-
Renewal	2007	Grand Valley-transformers	38,093	-	-	3,895	6,937	-	564	22,885	3,813		-
Regulatory	2007	Browns Farm	98,927		-	-	-	98,927	-	-	-	-	-
Regulatory	2007	Load Transfers	55,669	-	-	10,824	10,003	2,588	6,500	21,087	4,667	-	-
Inventory	2007	Transformer Inventory	(146,514)	-	-	-	-	-	-	(146,514)	-	-	-
Land Rights	2007	Land Rights	3,956	3,956	-	-	-	-	-	-	-	-	-
Metering	2007	Meter Installations	40,923	-	-	-	-	-	-	-	-	40,923	-
Metering	2007	Recorded Meter Inventory	94,460	-	-	-	-	-	-	-	-	94,460	-
	2007	Contributed Capital	(534,860)										(53,110)
Total			794,935	3,956	24,764	84,105	149,469	247,003	230,686	352,352	102,075	135,383	(534,860)

Category	In Service Date	Project Description	Total Project	Account 1905	Account 1915	Account 1920	Account 1925	Account 1930	Account 1935	Account 1940	Account 1945	Account 1955	Account 1960
Facilities	2007	Storage Building	157,383	157,383	-	-	-	-	-	-	-	-	-
Facilities	2007	General Plant	10,668	10,668	-	-	-	-	-	-	-	-	-
Equipment	2007	Mail Inserter	34,559	-	34,559	-	-	-	-	-	-	-	-
Hardware	2007	Misc Computer Hardware	14,090	-	-	14,090	-	-	-	-	-	-	-
Software	2007	Misc Computer Software	30,546	-	-	-	30,546	-	-	-	-	-	-
Vehicles	2007	Pickup Truck Replacement	31,645	-	-	-	-	31,645	-	-	-	-	-
Tools and Equip	2007	Stores Shelving	5,668	-	-	-	-	-	5,668	-	-	-	-
Tools and Equip	2007	Major Tool Replacement	4,799	-	-	-	-	-	-	4,799	-	-	-
Tools and Equip	2007	Voltage Tester	1,399	-	-	-	-	-	-	-	1,399	-	-
Tools and Equip	2007	Defibrillator	2,131	-	-	-	-	-	-	-	-	-	2,131
Total			292,887	168,051	34,559	14,090	30,546	31,645	5,668	4,799	1,399	-	2,131
		Total Capital Expenditures	1,087,822										

CUSTOMER DEMAND

2007 Project: Scotia Bank/Tim Hortons

Cost: $51,392 1845-$5,798 1850-$45,594

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: A new development on the west side of Town named Westside Market service for a Scotia Bank and Tim Hortons consisting of a PME and a 3-phase transformer. Contributed capital was received for this project as per OHL's Conditions of Service.

2007 Project: Veterans Way Completion 2006 and 2007

Cost: $132,841 $1830-$20,991 1835-$91,028 1850-$20,822

Need: In preparation and anticipation of Humber College site, a new Town well and pumping station, future subdivisions and to deal with some of the load transfer issues as per the DSC.

Scope: This part of the project consisted of the pole framing and the installation of the conductors and the transformers for 7 load transfer customers and the pumping station. Due to the economic downturn most of these projects are on hold. When we receive the new service connection requests contributed capital will apply.

2007 Project Wilside Pumping Station

Cost: $50,343 1845-$37,417 1850-$12,925

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: A new subdivision development required a new pumping station for the subdivision. An economic evaluation was performed and contributed capital was received for this project.

2007 Project Wilside Phase 4

Cost: $173,787 1840-$60,862 1845-$32,441 1850-$40,964
1855-$39,521

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: Connected and recorded the distribution and transformation plant installed by the developer for a new subdivision development in the south-east quadrant of Town. An economic evaluation was performed and contributed capital was received for this project.

2007 Project Credit Springs

Cost: $227,208 1840-$65,735 1845-$43,424 1850-$65,512
1855-$52,536

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: Connected and recorded the distribution and transformation plant installed by the developer for a new subdivision development in the south-east quadrant of Town. An economic evaluation was performed and contributed capital was received for this project.

SECURITY

2007 Project: Riddell Rd

Cost: $46,567 $1830-$23,448 1835-$23,119

Need: This project consisted of an extension of an existing line in an area of Town to provide a backup loop feed and to increase reliability for the customers in this area. There was a considerable amount of development in this area so OHL felt it was prudent to complete this loop feed at this time.

Scope: This project involved the hydro-vac installation of 6 poles and conductor and tie point switches.

RENEWAL

2007 Project: Burbank Rebuild Completion 2007

Cost: $125,546 1845-$28,754 1850-$96,792

Need: The cable in this area is over 30 years of age and has been damaged in the past few years by a number of faults. To improve reliability it was determined that the cable was at near end of life condition and therefore an extensive rebuild was warranted. We expected by performing this work it would help to decrease our callouts/outages thus decreasing our O&M expenses.

Scope: This project is a next portion of 2006 Burbank project. It consisted of the installation of new 28 kV primary cable and also new 16 kV padmount transformers in order to convert to the 27.6 kV circuit.

2007 Project: Centennial Road

Cost: $53,499 1840-$7,177 1845-$13,352 1850-$32,971

Need: This location was previously supplied by primary 4 kV overhead quad which is no longer industry standard. The 3 phase transformer at the neighbouring location required upgrading as it was undersized to now service the two locations. This installation was more economical option than installing a new transformer to service only the one building.

Scope: Upgraded the transformer and trenched and installed new secondary cable and a new main switch.

2007 Project: Pheasant Court

Cost: $41,077 1845-8,502 1850-$32,575

Need: The existing PMH unit required replacing due to maintenance costs as the unit required cleaning on a few occasions and there was contamination present along with moisture and dirt.

There were a number of faults and outages to a residential area that it supplied. Reliability was greatly affecting the area and many trouble calls were the main driver to perform the work.

Scope: A large PMH unit was replaced with a new PME due to a failure.

2007 Project: Miscellaneous Transformer Replacement

Cost: $54,890 1850-$49,242 1855-$5,648

Need: There were several transformers in different areas of Town that required replacement due to failure, leakage or deteriorating condition.

Scope: There were 9 locations that required outages to replace the transformers.

2007 Project: Transformer Replacement Grand Valley

Cost: $38,093 1830-$3,895 1835-$6,937 1845-$564
1850-$22,885 1855-$3,813

Need: OHL conducted oil sampling of all transformers in Grand Valley to test for PCB content in 2006. This indicated a need to replace few transformers due to the unacceptable PCB levels. To facilitate the changeout of the transformers a couple of pole required replacement due to age and to provide proper clearances..

Scope: Poles replaced and new transformers installed.

REGULATORY

2007 Project: Browns Farm -Completion 2005 to 2011

Cost: $98,927 1840-$98,927

Need: The Town of Orangeville was performing a complete civil engineering upgrade in this area. OHL felt it was prudent to take advantage of the excavation in preparation of future 27.6 kV conversion in this area.

Scope: Invoicing of contracted work completed in 2005 and 2006 for installation of new ductwork, road crossing duct banks.

2007 Project: Load Transfers

Cost: $55,669 1830-$10,824 1835-$10,003 1840-$2,588
1845-$6,500 1850-$21,087 1855-$4,667

Need: To eliminate the load transfers from Hydro One per Section 6.5.3 the Distribution System code for the effective date of January 31, 2009.

Scope: The installation of poles, conductors and transformers and service to the customers. One of the installation involved contractor costs to install conduit and underground cable to complete load transfer conversion. There were three locations involved in this process.

Metering

Cost: $94,460 1860-$94,460

In 2006, it came to our attention that the metering inventory in the amount of $94,460 was still being recorded in the inventory account of 1330 and was not in accordance with the OEB Accounting Procedures handbook. A journal entry was performed to record this amount into capital account 1860 in 2007.

GENERAL PLANT

2007 Project: Storage Facility

Cost: $157,383 1905-$157,383

Need: We required a storage building to store our transformers and wire and other line material to deal with security, storage issues and problems with parking lot drainage.

Scope: We obtained quotes from 2 sources to build a 5000 square foot building and prepare area to house the structure. OHL proceeded with the contract from the lowest bid.

2008 Capital Expenditures:

2008 Capital Expenditures

Category	In Service Date	Project Description	Total Project	Account 1806	Account 1820	Account 1830	Account 1835	Account 1840	Account 1845	Account 1850	Account 1855	Account 1860	Account 1995
Cust Demand	2008	C03-Roto Mill	51,301		-	-	-	-	17,438	33,863	-	-	
Cust Demand	2008	Edgewood Valley	228,773		-	-	-	135,094	35,742	32,753	25,184	-	
Cust Demand	2008	6 Misc New Services	103,595		-	-	-	-	27,167	76,427	-	-	
Cust Demand	2008	B06-Riddell Rd Pole Line	1,148		-	-	1,148	-	-	-	-	-	
Renewal	2008	Townline Rebuild	175,060		-	58,682	81,922	-	-	29,686	4,770	-	
Renewal	2009	Bredin Pkwy Conversion	351,389		-	-	-	172,883	29,623	148,883	-	-	
Renewal	2008	B08-Cardwell St. Conversion	35,597		-	3,063	11,513	-	-	21,021	-	-	
Renewal	2008	First St Transformer	10,849		-	-	-	-	-	10,849	-	-	
Renewal	2008	Misc Pole Replacement	20,483		-	7,003	(2,080)	-	-	15,560	-	-	
Renewal	2008	Misc Underground Projects	5,191		-	-	-	89	1,225	3,877	-	-	
Renewal	2008	Misc Transformer Replacements	8,008		-	-	-	-	-	8,008	-	-	
Renewal	2008	Grand Valley-Pole Replacement	76,189	-	-	20,905	33,713	-	-	19,909	1,481	182	
Substation	2008	Substation Betterments	12,969		12,969	-	-	-	-	-	-	-	
Substation	2008	DS 1 Removal	84,275		-	11,968	21,710	9,470	8,592	32,536	-	-	
Regulatory	2008	B09-Blind Line Pole Relocation	24,571		-	10,561	12,314	-	1,696	-	-	-	
Regulatory	2008	Load Transfer	4,712			331	1,409	-	-	2,972			
Inventory	2008	Transformer Inventory	150,485		-	-	-	-	-	150,485	-	-	
Metering	2008	Meter Installation	35,548		-	-	-	-	-	-	-	35,548	
	2008	Total Contributed Capital	(254,245)										(254,245)
Total			1,125,900	-	12,969	112,513	161,649	317,537	121,483	586,829	31,435	35,731	(254,245)

Category	In Service Date	Project Description	Total Project	Account 1905	Account 1915	Account 1920	Account 1925	Account 1930	Account 1935	Account 1940	Account 1945	Account 1955	Account 1960
Facilities	2008	Resurface Parking Lot	95,379	95,379									
Facilities	2008	Misc Building Improvements	14,111	14,111	-	-	-	-	-	-	-	-	-
Hardware	2008	Misc Computer Hardware	8,778	-	-	8,778	-	-	-	-	-	-	-
Software	2008	New CIS Initial Payment	50,753	-	-	-	50,753	-	-	-	-	-	-
Equipment	2008	Office Equipment	2,632	-	2,632	-	-	-	-	-	-	-	-
Equipment	2008	Replace Stores Equipment	1,188	-	-	-	-	-	1,188	-	-	-	-
Equipment	2008	Replace Major Tools	4,235	-	-	-	-	-	-	4,235	-	-	-
Equipment	2008	Replace Misc Equipment	11,876	-	-	-	-	-	-	-	-	-	11,876
Misc	2008	Grand Valley Adjustments	(278)	-	-	-	-	-	(278)	-	-	-	-
Total			188,673	109,490	2,632	8,778	50,753	-	910	4,235	-	-	11,876
		Total Capital Expenditures	1,314,574										

CUSTOMER DEMAND

2008 Project: Roto Mill

Cost: $51,301 1845-$17,438 1850-$33,863

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: A new industrial service required OHL to install a new pole and conductor for a road crossing. A three phase transformer and primary cable was also installed to provide service. Contributed capital as per OHL's Conditions of service was received for this project.

2008 Project: Edgewood Valley

Cost: $228,773	1840-$135,094	1845-$35,742	1850-$32,753
	1855-25,184		

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: Connected and recorded the distribution and transformation plant installed by the developer for a new subdivision development in the north-west quadrant of Town. An economic evaluation was performed and contributed capital was received for this project.

RENEWAL

2008 Project: Townline Rebuild

Cost: $175,060	1830-$58,682	1835-$81,922	1850-$29,686
	1855-$4,770		

Need: Upon inspection it was determined poles along this road required replacing because of age, deterioration and near end of life condition. Staying consistent to OHL policy and with expected new growth to this area, it was prudent when rebuilding that poles of sufficient height were installed.

Scope: Approximately 22 poles replaced and a new 27.6 circuit was installed to allow for future conversion in this area. Existing transformers were replaced due to age and to convert this area.

2008 Project: Bredin Parkway Conversion-Completion 2009

Cost: $351,389 1840-$172,883 1845-$29,623 1850-$148,883

Need: The existing subdivision was installed over 30 years ago and due to a number of faults to the area, the cable and transformers were approaching end of life condition. Callouts in this area uncovered poor installation methods of the contractor at the time. Risk of possible serious safety concerns were evident with the cable being installed at an insufficient depth.

Scope: A contractor used trenching methods and directional boring to install duct work to allow for the future installation of primary cable for this subdivision. New transformers, vaults and PME switching units were also installed to replace the existing plant.

2008 Project: Cardwell St Conversion

Cost: $35,597 1830-$3,063 1835-$11,513 1850-$21,021

Need: Inspection of this area identified a pole that required replacement due to age and deterioration. Both the 4 kV and 27.6 kV circuits were present on this pole and from previous work in this area OHL felt it prudent to complete the conversion at this time.

Scope: Removal and replacement with new pole, conductor changeover and new transformers installed.

2008 Project: Grand Valley Transformer/Pole Replacements

Cost: $76,819 1830-$20,905 1835-$33,713 1850-$19,909
1855-$1,481 1860-$182

Need: OHL conducted oil sampling of all transformers in Grand Valley to test for PCB content in 2006. This indicated a need to replace few transformers due to the unacceptable PCB levels. To facilitate the changeout of the transformers, poles required replacement due to age and to provide proper clearances.

Scope: This project consisted of replacing 6 poles in certain identified areas in the Village of Grand Valley. The transformers replaced as they were identified over the 50 ppm PCB levels of acceptable levels.

2008 Project: DS 1 Removal

Cost: $84,275	1830-11,968	1835-$21,710	1840-$9,470
	1845-$8,592	1850-$32,536	

Need: Conversion plan to eliminate this substation that is over 55 years old. Our DS #1 substation consists of 3-1 MVA transformers that have a manufacture date of 1954. Testing has been completed each year and various results indicated that these transformers are starting to deteriorate and approaching a near end of life condition. Due new development in our downtown core a 27.6 kV circuit was installed a number of years ago. It was determined by OHL that it would be more prudent to continue with the conversion in this area rather than completing expensive upgrades to the old 4 kV station. This station will be out of service in 2009 and scheduled to be removed by 2010.

Scope: In this segment of the project we converted parts of Green, Wellington, East Broadway and William Streets that are fed from that distribution station. This work consisted of identifying poles that required replacing due to age, deterioration and improper clearances. Replacement of transformers and primary cable at were replaced due to the improper voltages to allow for the conversion from 4 kV to 27.6 kV.

Transformer Inventory

The transformer inventory decreased due to all the transformers that were delivered in 2007 were installed during 2008.

GENERAL PLANT

2008 Project: Resurface Driveway/Parking Area Completion 2009

Cost: $95,379 1905-$95,379

Need: After the installation of the storage building was completed the parking required attention. The existing parking lot was crumbling from poor drainage and made it unsafe. Improvements to the entrance were required for the truck traffic for safety reasons. OHL requested 3 quotes and the lowest bid was rewarded.

Scope: The driveway required widening so that the trucks could maneuver. The parking area was shored up on the sides to give better drainage. The work commenced in late fall and with this phase only the first layer of asphalt was applied as it was suggested by the contractor to let settlement occur to allow for any repairs before applying finished coat of asphalt.

2008 Project: Harris CIS System Completion 2009

Cost: $50,753 1925-$50,753

Need: Our current customer information system vendor has been sold and there will no longer be support for the Ontario Deregulated Environment by the new software vendor owner. Harris Northstar CIS is the replacement of Advanced CIS Infinity. OHL participated in an RFP with a group of LDC's that were in the same situation, named CODAC. The vendors conducted session from demonstrating functionality and prices were given based on the group of LDCs. OHL considered many options and decided the UCS solution along with 3 other LDCs as the best cost effective system. A copy of the recommendation to our Board of Directors is attached as Appendix A under Exhibit 2, Tab , Schedule . The system is to be implemented in the Fall of 2009.

Scope: Initial payment toward the system.

ACCUMULATED DEPRECIATION:

Table 1 - Accumulated Depreciation

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Bridge ($)	Variance from 2008 Actual	2010 Test ($)	Variance from 2009 Bridge
Land and Buildings											
1805-Land											
1806-Land Rights	3,306	5899.23	2,593	7251.89	1,353	8604.55	1,353	9957.21	1,353	11,310	1,353
1808-Buildings and Fixtures	15,296	15,296		15,296		15,296		15,296		15,296	
1905-Land											
1906-Land Rights	4,938	4,938		4,938		4,938		4,938		4,938	
1810-Leasehold Improvements	5,256	5,256	0		(5,256)						
Sub-Total-Land and Buildings	28,797	31,390	2,593	27,486	(3,904)	28,839	1,353	30,191	1,353	31,544	1,353
DS											
1820-Distribution Station Equipment - Normal	438,968	496,427	57,459	523,378	26,951	547,524	24,146	572,637	25,113	599,809	27,172
Sub-Total-DS	438,968	496,427	57,459	523,378	26,951	547,524	24,146	572,637	25,113	599,809	27,172
Poles and Wires											
1830-Poles, Towers and Fixtures	2,019,780	2,357,622	337,842	2,498,570	140,947	2,639,343	140,774	2,786,094	146,750	2,933,683	147,589
1835-Overhead Conductors and Devices	1,282,150	1,551,895	269,745	1,667,893	115,998	1,785,256	117,364	1,910,605	125,349	2,041,062	130,457
1840-Underground Conduit	1,045,991	1,302,541	256,550	1,418,320	115,779	1,540,449	122,129	1,673,901	133,452	1,812,024	138,123
1845-Underground Conductors and Devices	1,202,052	1,512,383	310,331	1,648,594	136,211	1,786,816	138,222	1,934,970	148,153	2,090,083	155,113
Sub-Total-Poles and Wires	5,549,973	6,724,441	1,174,468	7,233,376	508,935	7,751,865	518,489	8,305,570	553,705	8,876,852	571,282
Line Transformers											
1850-Line Transformers	2,350,823	2,941,715	590,892	3,206,206	264,491	3,482,433	276,227	3,796,916	314,483	4,125,383	328,468
Sub-Total-Line Transformers	2,350,823	2,941,715	590,892	3,206,206	264,491	3,482,433	276,227	3,796,916	314,483	4,125,383	328,468
Services and Meters											
1855-Services	949,234	1,170,542	221,308	1,263,817	93,275	1,357,492	93,675	1,449,624	92,132	1,543,967	94,343
1860-Meters	731,535	870,052	138,517	930,147	60,095	990,957	60,810	1,053,136	62,179	1,117,135	63,999
Sub-Total-Services and Meters	1,680,768	2,040,594	359,825	2,193,965	153,371	2,348,449	154,484	2,502,760	154,311	2,661,102	158,342
General Plant											
1908-Buildings and Fixtures	566,136	667,995	101,858	712,284	44,290	756,729	44,444	803,689	46,961	850,750	47,061
Sub-Total-General Plant	566,136	667,995	101,858	712,284	44,290	756,729	44,444	803,689	46,961	850,750	47,061
IT Assets											
1920-Computer Equipment - Hardware	189,690	167,274	(22,416)	179,642	12,368	162,348	(17,294)	180,964	18,616	205,360	24,396
1925-Computer Software	171,339	245,606	74,266	286,953	41,348	330,925	43,972	412,924	81,999	506,801	93,877
Sub-Total-IT Assets	361,029	412,879	51,850	466,595	53,716	493,273	26,678	593,888	100,615	712,161	118,273
Equipment											
1915-Office Furniture and Equipment	122,583	119,314	(3,268)	128,922	9,607	134,141	5,219	143,437	9,295	153,982	10,545
1930-Transportation Equipment	610,286	592,486	(17,800)	665,533	73,047	733,921	68,388	803,026	69,105	876,194	73,168
1935-Stores Equipment	22,863	23,149	287	25,067	1,917	22,668	(2,398)	24,347	1,678	26,025	1,678
1940-Tools, Shop and Garage Equipment	145,982	117,042	(28,940)	125,416	8,375	131,401	5,985	135,828	4,427	140,505	4,677
1945-Measurement and Testing Equipment	5,635	9,115	3,480	10,647	1,532	12,179	1,532	13,537	1,358	14,946	1,408
1955-Communication Equipment	14,182	12,795	(1,387)	13,803	1,007	14,810	1,007	15,818	1,007	16,825	1,007
1960-Miscellaneous Equipment	3,457	1,682	(1,775)	2,479	797	2,264	(216)	5,697	3,434	9,131	3,434
Sub-Total-Equipment	924,989	875,585	(49,404)	971,867	96,282	1,051,384	79,517	1,141,690	90,306	1,237,608	95,918
Other Distribution Assets											
1970-Load Management Controls - Customer										1,100	1,100
1980-System Supervisory Equipment										500	500
1995-Contributions and Grants - Credit	(247,105)	(460,985)	(213,880)	(574,272)	(113,287)	(692,644)	(118,372)	(834,655)	(142,011)	(982,422)	(147,768)
Sub-Total-Other Distribution Assets	(238,245)	(451,636)	(213,391)	(564,771)	(113,135)	(692,644)	(127,872)	(834,655)	(142,011)	(980,822)	(146,168)
ACCUMULATED DEPRECIATION TOTAL	11,663,237	13,739,390	2,076,152	14,770,385	1,030,995	15,767,852	997,467	16,912,687	1,144,835	18,114,388	1,201,701

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION:

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identifiable assets. The 2006 Board Approved closing balance for accumulated depreciation is based on OHL's 2004 year end account balances, plus Tier 1 capital adjustments approved in OHL's 2006 EDR Application. As such, the variance between 2006 Board Approved and 2006 Actual represents two years of depreciation changes, and in order to arrive at the annual impact, the variance must be divided by two.

From 2006 Actual to the 2010 Test Year the above table shows that the change in accumulated depreciation, which has not changed materially from year to year. The depreciation expense in the year for each of the above accounts is different due to the assets that are recorded as an overhead expense. The change in accumulated depreciation is a result of capital expenditures over a four year period. Since a detailed analysis of capital expenditures has been provided in this Exhibit, no further explanation of the changes in accumulated depreciation accounts is required.

CAPITAL BUDGET:

Introduction

OHL has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending for the 2009 Bridge Year and the 2010 Test year is broken down by account and by project in Exhibit 2, Tab 3, Schedule 2. As projects can be charged to different OEB capital accounts, additional accounts have been identified where required. Below is an analysis of OHL's capital spending from 2005 to 2006.

Year	Distribution Plant	General Plant	Total Capital Expenditures	Increase/ Decrease	% Increase/ Decrease
2005	726,236	97,859	824,095		
2006	844,540	444,129	1,288,669	464,574	56%
2007	794,935	292,887	1,087,822	(200,847)	-16%
2008	1,125,900	188,673	1,314,574	226,752	21%
2009	1,292,828	410,999	1,703,826	389,253	30%
2010	52,404	65,000	1,934,937	231,111	14%

In 2006, the main driver of the increase of 56% in capital expenditures was due to the double bucket truck purchase amounting to $316,548 along with the increase in the transformer inventory for purchases for new service installations in 2007.

In 2007, the main driver of the decrease of -16% was largely due to the new commercial development of the west side of Town where all work performed was contributed capital projects.

In 2008, the main driver of the increase of 21% were projects that related less to contributed capital and the Bredin Parkway project amounting to $351,389 that could not be delayed further due to the safety risk.

In 2009, the main driver of the 30% increase over 2008 is work relating to projects where the Town received infrastructure funding from the government such as Hansen Blvd reconstruction costing $289,343. The new CIS system project that could not be deferred amounting to 158,050 and the purchase of a new single bucket truck for $130,000 also contributed to the increase.

In 2010, the main driver of the 14% increase over 2009 is need to upgrade the wholesale meter CT at a cost of $100,000, the installation of feeder extensions for renewable generation projects amounting to $136,000, an optimization study to assist with asset management and the remote sensors that will give OHL the ability to control customer’s loads.

ASSIGNMENT OF CAPITAL PROJECTS TO USoA:

2009 Capital Expenditures

2009 Capital Expenditures

Category	In Service Date	Project Description	Total Project	Account 1806	Account 1820	Account 1830	Account 1835	Account 1840	Account 1845	Account 1850	Account 1855	Account 1860	Account 1995
Cust Demand	2009	Orangeville Highlands	308,087		-	-	-	114,167	59,520	60,000	74,400	-	
Cust Demand	2009	Broadway Grande	55,920		-	-	-	-	-	55,920	-	-	
Cust Demand	2009	Montgomery Village-Phase H	108,787		-	-	-	41,787	14,320	35,100	17,580	-	
Cust Demand	2009	Hydro One Rebuild	162,522		-	69,276	58,782	-	3,762	30,702	-	-	
Cust Demand	2009	5 Misc New Services	175,349		-	-	-	-	28,362	133,962	-	13,025	
Renewal	2009	Second Street Conversion	71,848		-	8,602	19,363	6,500	5,492	29,285	-	2,605	
Renewal	2009	Rolling Hills Refurbishment	92,876		-	-	-	14,672	16,610	61,593	-	-	
Renewal	2009	Faulkner Conversion	63,084		-	-	-	15,077	16,870	31,137	-	-	
Renewal	2009	Bredin Pkwy Conversion	129,221		-	-	-	23,172	66,837	39,212	-	-	
Renewal	2009	Ponsford & Emma	32,622			2,526	15,252	-	-	4,918	9,926	-	
Renewal	2009	Misc Pole Replacement	17,096		-	10,730	4,066	-	-	-	2,300	-	
Renewal	2009	4 Robb Blvd	22,751		-	-	-	4,407	5,672	12,672	-	-	
Substation	2009	DS#1 Removal	110,446		-	22,387	18,807	-	15,402	53,850	-	-	
Substation	2009	Re-Gravel 4 Substations	7,382		7,382	-	-	-	-	-	-	-	
Regulatory	2009	Centennial and C Line	40,684		-	5,058	18,102	885	7,674	8,965	-	-	
Regulatory	2010	William St	30,604		-	21,845	5,095	-	-	-	3,665	-	
Regulatory	2010	Hansen Street Reconstruction	289,343			6,485	9,470	49,858	130,089	93,441	-	-	
Regulatory	2009	Riddell Rd Improvements	32,766		-	-	-	32,766		-	-	-	-
		Contributed Capital	(458,562)										(458,562)
Total			1,292,828		7,382	146,908	148,936	303,293	370,611	650,758	107,871	15,630	(458,562)

Category	In Service Date	Project Description	Total Project	Account 1905	Account 1915	Account 1920	Account 1925	Account 1930	Account 1935	Account 1940	Account 1945	Account 1955	Account 1960
Facilities	2009	General Plant	17,000	17,000									
Hardware	2009	Misc Computer Hardware	22,100			22,100							
Software	2009	New CIS (Northstar)	158,050				158,050						
Software	2009	File Nexus	43,969				43,969						
Software	2009	Misc Computer Software	14,125				14,125						
Vehicles	2009	Single Bucket Truck Replacemen	130,000					130,000					
Tools & Equip	2009	Major Tool Replacement	11,000						5,000	5,000	1,000		
Tools & Equip	2009	Misc Equipment	14,755										14,755
Total			410,999	17,000	-	22,100	216,144	130,000	5,000	5,000	1,000	-	14,755
		Total Capital Expenditures	1,703,827										

CUSTOMER DEMAND

2009 Project: Orangeville Highlands

Cost: $308,087 1840-$114,167 1845-$59,520 1850-$60,000
1855-$74,400

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: An estimate in capital costs has been received for this subdivision and the subdivision is scheduled to be connected in 2009. An economic evaluation was performed using the estimates and contributed capital will be received for this project.

2009 Project: Broadway Grande

Cost: $55,920 1850-$55,920

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: An estimate in capital costs has been received for this subdivision and the subdivision is scheduled to be connected in 2009. An economic evaluation was performed using the estimates and contributed capital will be received for this project.

2009 Project: Montgomery Village 2, Phase H

Cost: $108,787 1840-$41,787 1845-$14,320 1850-$35,100
1855-$17,580

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: An estimate in capital costs has been received for this subdivision and the subdivision is scheduled to be connected in 2009. An economic evaluation was performed using the estimates and contributed capital will be received for this project.

2009 Project: Hydro One Rebuild

Cost: $162,522 1830-$69,276 1835-$58,782 1845-$3,762
1850-$30,702

Need: Hydro One requested OHL to rebuild existing line along Water and Emma Streets in the Village of Grand Valley to provide sufficient clearance for a new 44 kV and a new 7200 kV circuit as per the joint use agreement. OHL will transfer their existing 7200 kV circuit to the new poles as well.

Scope: Installation of approximately 20 poles to replace the existing pole line. The transfer of the existing circuit, transformers and services will also be completed. Contributed capital will be calculated per the joint-use agreement with Hydro One.

RENEWAL

2009 Project: Second St Conversion

Cost: $71,848 1830-$8,602 1835-$19,363 1840-$6,500 1845-$5,492
1850-$29,285 1860-$2,605

Need: The majority of Second Street has been rebuilt and converted in the early 2000s'. This project is final segment of the conversion. A joint venture with OHL and the customer has been initiated to upgrade their service that is no longer ESA standard. The existing transformer at the customer's location is located inside the building which is a safety issue. This will now allow us to finish the conversion.

Scope: Project consists of two parts, installation of new primary u/g cable and transformer at building and rebuild and removal of old 4kv on Second St. and in rear lane of Second Ave. The old poles and 4kv transformers are approximately 40 years of age. Replacements will be converted to 27.6kv.

2009 Project: Rolling Hills Refurbishment

Cost: $92,876 1840-$14,672 1845-$16,610 1850-$61,593

Need: In the mid-1990's there were two services installed on a temporary basis that required future PME switching units. This project has been delayed because the service to a significant number of customers will be affected by an outage. A K-Bar unit was installed on one of the services and the second primary cable was coiled in a transformer vault.

Scope: Install new P.M.E units and terminate existing U/G primary cable to complete loop feed in 27.6kv system on Rolling Hills area. Also provides backup for the service to Headwaters Hospital. The P.M.E. unit will also provide fusing for the new small plaza scheduled for development on Rolling Hills Drive. Contributed capital will be received for a portion of the PME unit that will supply a new service for a plaza development.

2009 Project: Faulkner Street Conversion

Cost: $63,084 1840-$15,077 1845-$16,870 1850-$31,137

Need: OHL performed estimated load calculations for the proposed new Lord Dufferin Centre retirement complex and it was determined that a development of this size we would be better served off our 27.6 kV plant. We do not want to put the load of the development on our old 4 kV system.

Scope: We will trench and install new primary cable and a P.M.E. switching unit at this property to feed a future development and remove the 4Kv according to our plan. An existing P.M.E. on Faulkner and Zina will be used to provide a feed off the 27.6 kV system. Contributed capital will be received for the portion of the PME that the new service will be using.

2009 Project: Bredin Parkway Conversion Completion 2008-2009

Cost: $129,221 1840-$23,172 1845-$66,837 1850-$39,212

Need: A segment of this project was commenced in 2008. The existing subdivision was installed approximately 30 years ago and due to a number of faults to the area, the cable and transformers were approaching near end of life condition. Callouts in this area uncovered poor installation methods of the contractor at the time. Risk of possible serious safety concerns were evident with the cable being installed at an insufficient depth.

Scope: A contractor completed the remainder of the trenching and directional boring to install duct work to allow for the future installation of primary cable for this subdivision. New transformers and vaults were also installed to replace the existing plant.

2009 Project: Ponsford & Emma

Cost: $32,622 1830-$2,526 1835-$15,252 1850-$4,918 1855-$9,926

Need: Hydro One completed an upgrade of their pole lines along Ponsford and Emma Streets in the Village of Grand Valley. As per the joint use agreement OHL was required to transfer the existing circuit to the new poles.

Scope: The transfer of the existing circuit, transformers and services was also completed.

SUBSTATION

2009 Project: DS 1 Removal

Cost: $110,446 1830-22,387 1835-$18,807 1845-$15,402
1850-$53,850

Need: Conversion plan to eliminate this substation that is over 55 years old. Our DS #1 substation consists of 3-1 MVA transformers that have a manufacture date of 1954. Testing has been completed each year and various results indicated that these transformers are starting to deteriorate and approaching a near end of life condition. As a result of new development in our downtown core a 27.6 kV circuit was installed a number of years ago. It was determined by OHL that it would be more prudent to continue with the conversion in this area rather than completing expensive upgrades to the old 4 kV station. We are aiming to have this station removed by 2010.

Scope: In this segment of the project we converted parts of Armstrong and Mill Streets that are fed from that distribution station. This work consisted of identifying poles that required replacing due to age, deterioration and improper clearances. Replacement of transformers and primary cable at were replaced due to the improper voltages to allow for the conversion from 4 kV to 27.6 kV.

REGULATORY

2009 Project: Centennial And C Line

Cost: $40,684 1830-$5,058 1835-$18,102 1840-$885
1845-$7,674 1850-$8,965

Need: Orangeville Hydro was requested by the Town of Orangeville to relocate a pole to allow for widening the intersection and new sidewalk installation.

Scope: An existing service on Centennial Road was previously fed off a Hydro One pole on C Line. Trenching and new primary underground cable was installed so the service could be converted from the 4 kV to the 27.6 kV system on an OHL pole. A new three phase transformer is required. As this project is municipally driven, OHL will receive 50% contributed capital towards labour and trucking.

2009 Project: William St

Cost: $30,604 1830-$21,845 1835-$5,095 1855-$3,665

Need: Orangeville Hydro was requested by the Town of Orangeville due to reconstruction of the civil infrastructure to allow for widening the street and new sidewalk installation.

Scope: Installation of 8 new poles due age and deterioration and transferring of all secondary conductor and services.

2009 Hansen Street Reconstruction

Cost: $289,343 1830-$6,485 1835-$9,470 1840-$49,858
1845-$130,089 1850-$93,441

Need: With the reconstruction of the road work on Hansen Blvd, we are converting this area to underground due to a prior arrangement with the town, as the overhead circuit was a temporary arrangement when installed. The agreement with the Town was 20 years ago to build the overhead line until the reconstruction of this road.

Scope: The work will include the removal of the overhead circuit and poles on Hansen Blvd , relocation of a pole located at First St and Hansen Blvd, as well as the installation of three new PME's on Hansen Blvd and the installation of 1000 MCM express cable from First St to Amelia.

2009 Riddell St Infrastructure Improvements

Cost: $32,766 1840-$32,766

Need: With the infrastructure improvements, curbing and sidewalks on Riddell, OHL used this opportunity to have the contractor install ductwork from Alder to a PME unit on Riddell. This was necessary to complete a loop feed for reliability in this area that was previously removed when a pole line was removed during construction of the Alder Street sports complex.

Scope: The installation of ductwork.

GENERAL PLANT

2009 Project: Harris CIS System-Completion 2009

Cost: $158,050 1925-$158,050

Need: Our current customer information system vendor has been sold and there will no longer be support for the Ontario Deregulated Environment by the new software vendor owner. Harris Northstar CIS is the replacement of Advanced CIS Infinity. OHL participated in an RFP with a group of LDC’s that were in the same situation, named CODAC. The vendors conducted session from demonstrating functionality and prices were given based on the group of LDCs. OHL considered many options and decided the Utility Collaborative Services (UCS) solution along with 3 other LDCs as the best cost effective system. Please see the presentation made to our Board of Directors in Appendix A. The system is to be implemented in the Fall of 2009.

Scope: Remainder of payment. Training and set up sessions to be ready for conversion in the Fall 2009.

2009 Project: File Nexus System

Cost: $43,969 1925-$43,969

Need: This project as part of our association with the UCS group will allow us to reduce the amount of paper print out of journals and reports, thus reducing the cost of paper, storage, employee time handling paper, etc.

Scope: Working with UCS to scan invoices, engineering drawings etc. that will assist staff to work more efficiently and eliminate the need for large storage areas.

2009 Project: Vehicle Replacement

Cost: $130,000 1930-$130,000

Need: OHL was experiencing recurring and higher maintenance costs on the existing single bucket truck 1996 model. OHLs replacement schedule is 12 years for large vehicles. OHL received 3 different supplier quotes that were relatively close and chose the model at a comparable price that best suited our operations.

Category	In Service Date	Project Description	Total Project	Account 1605	Account 1820	Account 1830	Account 1835	Account 1840	Account 1845	Account 1850	Account 1855	Account 1860	Account 1995
Cust Demand	2010	Edgewood Valley	52,277			-	-	21,544	7,981	13,440	9,312	-	
Cust Demand	2010	Broadway Grande	239,029			-	-	63,120	33,157	101,593	41,160	-	
Cust Demand	2010	Mono Development Ph 4	211,889			-	-	50,203	26,146	102,858	32,682	-	
Cust Demand	2010	4 Misc New Services	114,676			-	-	-	23,290	82,690	-	8,695	
Renewal	2010	Orangeville Mall Conversion	90,462			8,318	6,060	10,498	11,238	54,350	-	-	
Renewal	2010	Browns Farm Conversion	318,895			-	-	46,646	67,251	204,999	-	-	
Renewal	2010	C Line Conversion	80,999			-	-	9,709	17,468	53,822	-	-	
Renewal	2010	Misc Pole Replacement	24,990			9,815	15,175	-	-	-	-	-	
Renewal	2010	King St Rebuilds	26,780			11,893	6,135	-	-	8,753	-	-	
Renewal	2010	Water Street Removal 7200 kV	42,247			-	10,503	10,693	11,388	9,664	-	-	
Renewal	2010	Broadway Removal Old Circuit	84,634			-	3,635	9,709	17,468	53,822	-	-	
Renewal	2010	Remove Old 4 kV Rear Lot	34,783			-	-	6,813	14,735	13,235	-	-	
Renewal	2010	Centennial Road Removals	40,619			11,914	28,705	-	-	-	-	-	
Regulatory	2010	Shirley St., Marion St	15,349			-	3,371	4,610	7,367	-	-	-	
Reliability	2010	Fault Indicators Replacement	55,697			-	55,697	-	-	-	-	-	
Substation	2010	DS#1 Removal Project	11,127		11,127								
Metering	2010	Wholesale Meter M5 & M26	100,000		100,000								
Metering	2010	>50 Class Meter Upgrades	57,276									57,276	
Reliability	2010	Remote Sensors	50,601				50,601						
Green Energy Act	2010	Large Renewable Generation-Other	136,202				50,601		85,601				
Green Energy Act	2010	MicroFIT Enablement	52,404								27,404	25,000	
Reliability	2010	Optimization Study	62,253		12,451		24,901		24,901				
	2010	Total Contributed Capital	(287,833)										(287,833)
Total			1,615,357	-	123,578	41,939	255,384	233,544	347,990	699,225	110,559	90,971	(287,833)

Category	In Service Date	Project Description	Total Project	Account 1905	Account 1915	Account 1920	Account 1925	Account 1930	Account 1935	Account 1940	Account 1945	Account 1970	Account 1980
Facilities	2010	Washroom Renovations	10,000	10,000									
Equipment	2010	Telephone System	25,000		25,000								
Hardware	2010	Computer Hardware	57,800			57,800							
Software	2010	Misc Computer Software	118,780				118,780						
Vehicles	2010	Replace Vehicles	65,000					65,000					
Tools & Equip	2010	Major Tool Replacement	6,000							5,000	1,000		

CUSTOMER DEMAND

2010 Project: Edgewood Valley Phase 1B

Cost: $52,277 1840-$21,544 1845-$7,981 1850-$13,440
1855-$9,312

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: An estimate of the capital costs for the distribution and transformation assets has been received for this subdivision and the subdivision is scheduled to be connected in 2010. An economic evaluation was performed using the estimates and contributed capital will be received for this project.

2010 Project: Broadway Grande

Cost: $239,029 1840-$63,120 1845-$33,157 1850-$101,593
1855-$41,160

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: An estimate of the capital costs for the distribution and transformation assets has been received for this subdivision and the subdivision is scheduled to be connected in 2010. An economic evaluation was performed using the estimates and contributed capital will be received for this project.

2010 Project: Mono Development Phase 4

Cost: $211,889 1840-$50,203 1845-$26,146 1850-$102,858
1855-$32,682

Need: Orangeville Hydro is obligated under the DSC to connect new customer services that are funded through contributed capital.

Scope: An estimate of the capital costs for the distribution and transformation assets has been received for this subdivision and the subdivision is scheduled to be connected in 2010. An economic evaluation was performed using the estimates and contributed capital will be received for this project.

RENEWAL

2010 Project: Orangeville Mall Conversion

Cost: $90,462 1830-$8,318 1835-$6,060 1840-$10,498
1845-$11,238 1850-$54,350

Need: Orangeville Mall is one of OHL's most significant customers and currently this location is fed off the older 44 kV circuit with no loop feed potential in case of outages. For reliability this customer would be better serviced off our 27.6 kV which is now available off Hansen Blvd that is loop fed thus increasing reliability. We can then eliminate approximately 2 kilometers of old 44 kV circuit that only services this one customer. Many of these existing poles are at end of life condition with porcelain insulators and would require replacing.

Scope: Removal of the old poles and 44 kV conductor. The installation of underground primary cable and 2 three-phase transformers.

2010 Project: Browns Farm Conversion 2005 to 2011

Cost: $318,895 1840-$46,646 1845-$67,251 1850-204,999

Need: The Town of Orangeville was performing a complete civil engineering upgrade in this area. OHL felt it was prudent to take advantage of the excavation in preparation of future 27.6 kV conversion in this area that started in 2005. This is another segment of the conversion project which now will include cable and transformer replacement and expected to continue into 2011. The old hydro infrastructure is now over 30 years of age and maintaining reliability is becoming a concern.

Scope: The installation of new primary cable, 24 transformers and 2 PME switchgears.

2010 Project: C Line Conversion

Cost: $80,999 1840-9,709 1845-$17,468 1850-53,822

Need: Conversion of these services will allow for the removal of an old 4kv circuit on C-Line north of Centennial Rd. The deterioration of the transformers and cable due to age and nearing end of life condition was determined in our asset management inspections. To stay consistent with our policy and as the 27.6 kV circuit is present, all upgrades involve conversion.

Scope: The upgrade of 3 primary services involving the replacement of primary cable and transformers. Once the Browns Farm subdivision is converted as well as these services we will be able to remove an old 4 kV circuit that is presently on Hydro One poles as per the joint use agreement.

2010 Project: King Street Rebuild

Cost: $26,780 1830-$11,893 1835-$6,135 1850-$8,753

Need: During our distribution inspections of the area, it was determined that the poles needed to be replaced due to age and improper clearances.

Scope: Replacement of 4 poles, transferring the existing 7200 kV circuit and transformers.

2010 Project: Water Street

Cost: $42,247 1835-$10,503 1840-$10,693 1845-$11,388
1850-$9,664

Need: During our distribution inspections of the area, it was determined that the existing pole line needs replacement due to age and deterioration. As a new circuit was installed in Emma Street in 2009, the overhead circuit is not longer required. To service existing customers OHL decided to convert to underground to improve appearance and reliability.

Scope: The installation of underground primary cable and two single phase padmount transformers.

2010 Project: Broadway Removal of Old Circiut

Cost: $84,634 1830-$3,635 1835-$9,709 1840-$17,468
1845-$53,822

Need: During our asset inspections, the existing pole line that is situated in the rear lots on the south side of Broadway required to be replaced. OHL determined it would be more cost effective to convert these 3 services and allow the removal of this old pole line as it is impossible to access these poles. This will now allow the 4 kV circuit to be removed that also fed the Browns farm area also forecasted to be converted in 2010.

Scope: Installation of primary underground cable and transformers to be fed off the existing 27.6 kV circuit from Broadway. The removal of the old poles and conductor from the rear lots.

2010 Project: Remove Old 4 kV Rear Lot

Cost: $34,783 1840-$6,813 1845-$14,735 1850-$13,235

Need: It is difficult to access the poles and existing circuit in this older area that was identified during our asset inspection. It was determined that by removing the circuit we would be increasing reliability and the overhead primary in the rear lots of this residential area is also a safety concern.

Scope: Installation of underground primary cable and transformers will allow for the removal of the old overhead primary circuit. This new service will be fed from the 27.6 kV system thus converted from the 4kV.

2010 Project: Centennial Road

Cost: $40,619 1830-$11,914 1835-$28,705

Need: We have been gradually upgrading an existing pole line in an older industrial area due to age, deterioration and inadequate clearances. Improper framing standards were used a number of years ago when the 27.6 kV circuit was installed in this area. With the expected growth of new commercial services in this area, OHL upgraded the line to provide adequate clearances for safety and increased reliability.

Scope: The replacement of 3 poles and changeover of the conductor and converted transformer to the 27.6 kV standard.

RELIABILITY

2010 Project: Fault Indicators

Cost: $55,697 1835-$55,697

Need: OHL asset condition assessment determined that 10 fault indicators dire need of replacement.

Scope: OHL will install 10 fault indicators.

METERING

2010 Project: Wholesale Meter CT/PT

Cost: $100,000

M5:
There is one Voltage Transformer that is not Measurement Canada approved and this VT is on the dispensation list. Hydro One will perform a site visit to plan a scope of work and cost estimate will be prepared by Hydro One and forwarded within 3 months of the site visit. The target in service date will be approximately 18 months from acceptance of the proposal and Hydro One's receipt of a purchase order. .

MACD: In order to protect Orangeville Hydro from possible sanctions from the IESO's Market Assessment & Compliance Division (MACD) Orangeville Hydro self-reported to MACD that the M26 CTs and the M5 VT would not be replaced before the Dec 31/09 expiry of the dispensation list. The reason for not meeting the deadline for replacement of the instrument transformers was not due to lack of action on Orangeville Hydro part but due to a high demand and a lack of resources at Hydro One. As the instrument transformers are assets belonging to Hydro One, Orangeville Hydro cannot act alone to carry out the replacement. When we received confirmation that the M26 CTs were indeed approved we notified MACD of this and MACD sent a letter acknowledging the change to the status of the M26. However, the self-report to MACD pertaining to the M5 VT is still active.

2010 Project: >50 Class Meter Upgrades

Cost: $ 57,276 1860-$57,276

Need: OHL has budgeted this metering project to allow the larger general service that do not have an interval meters the ability to manage their usage and to assist with their conservation efforts. This movement to interval meters will also reduce meter reading costs as OHL is installing Smart meters for residential and small general service customers in the Spring of 2010. There are 104 meters remaining that are not capable of recording or communicating time of use data. There will be economic savings in purchasing them at the same as the others as there is a minimum quantity order number of 96 meters for each meter type. OHL will also upgrade 2.5 element meter installations to 3 elements according to the directive issued by Measurement Canada when the opportunity (such as a meter change) presents itself.

Scope: The purpose of the project is to change out all of the non interval type meters that are currently installed on sites where the customers load is greater than 50 Kilowatts (KW) and the customer is being billed for demand changes.

GREEN ENERGY ACT

2010 Project: Remote Sensors

Cost: $ 50,601 1835-$50,601

Need: OHL requires the installation of remote sensors as the beginning steps of SCADA and Smart Grid will provide better information as to system loading and power outages. This will also control load and provide better data for conservation.

Scope: OHL will install 10 remote sensors in this phase.

2010 Project: Large Renewable Connections

Cost: $ 136,202 1835-$50,601 1845-$85,601

Need: OHL has been approached by five solar proponents that will be installing solar renewable energy solutions. One proponent is looking at installing 500 kW systems at Walmart, Canadian Tire and Home Depot

Scope: OHL will install feeder extensions for three installations totalling1.5 MW. OHL has calculated these installations based on EB-2009-0077 where it states, “the Board is proposing to set the cap at $90,000/MW”

2010 Project: MicroFIT Enablement

Cost: $ 52,404 1855-$27,404 1860-$25,000

Need: Based on several inquiries to assist customers with their conservation efforts , OHL will install services and metering

Scope: The installation of services and metering estimated to be approximately 100 customers.

2010 Project: Optimization Study

Cost: $ 62,253 1820- $12,451 1835-$24,901 1860-$24,901

Need: OHL considers management of system losses in the planning and operation of our distribution system. After completion of our asset condition assessment , OHL is striving to move ahead with our Asset Management plan and recognizes the need for an optimization study and analysis of our distribution system.

Scope: The purpose is to optimize the entire distribution system including all feeders and voltage levels. Feeder analysis for phase balancing and capacitor optimization and configuration optimization analysis to obtain the best switching arrangements. OHL has received one request for quotation to take all required data and enter it into software and provide all related reports and output files. Before proceeding OHL is waiting to receive two more RFQs.

GENERAL PLANT

2010 Project: Computer Hardware

Cost: $57,800 1920-$57,800

Need: Computer hardware is used by all departments of the utility and is key in customer service, improving reliability and reducing costs. Orangeville Hydro Computer purchase and deployment mandate: Upgrades are based on business software requirements. With the constant upgrades to business specific software, Orangeville Hydro may maintain the standard computer configuration required by software vendors. Upgrade to maintain customer service levels, in order to maintain prompt response to customer inquiries and billing creation, it is often necessary to increase processing level of hardware primarily used for customer service. Replace obsolete equipment; as equipment ages it loses the ability to run required operating systems and standard software applications. PC deployment is based on user specific requirements. CPUs are to be deployed based solely on the business need. Deployment is dependent upon the level of processing power each user requires to efficiently manage the business need, not based on user perception of requirements or perceived obsolescence of equipment. The deployment scheme assures Orangeville Hydro that assets are maintained for the maximum length of time and as importantly, each computer deployment is based specifically on user needs. Benefits of new equipment reduces the dependence on IT and support of older hardware, taking advantage of new technologies, empowering employee productivity with right equipment to complete their jobs efficiently, improved access to data and information, adhering to best practices and allowing for growth.

Scope: Major projects included two new servers that will be purchased for approximately $40,000 and replacement of our engineering plotter. The server that hosts our financial software and database has reached its' life expectancy and performance is deteriorating. In order to house and perform output for the newer version of software it is pertinent to business needs to have a reliable server with appropriate processing power. The other server will be required for the SCADA system that OHL is implementing in 2010.

2010 Project: Computer Software

Cost: $118,780 1925-$118,780

Need: Computer software, whether operating system software or application software, are programs written in machine-readable languages, that control the operations of hardware or that enable users to perform certain tasks on computers. The OS software controls the hardware and manages its internal functions: controls input, output and storage, and handles its interaction with application programs. Application software enables users to accomplish particular tasks. In this day and age, the functioning of computer software is tied closely into the hardware it resides on and it is important that the specs of any CPU or server is appropriate for the software being installed. Benefits: improved productivity from software enhancements, employee empowerment, keeping up to date with industry standards, ease of integration to other applications, reduced costs - common operating system, higher security, reduced dependence on IT services, improved tools for web development/design.

Scope: Major projects are replacing current mapping system with GIS/Engineering Software, upgrading our financial software and project management. OHL will be upgrading our Great Plains/Wennsoft to the most recent version and also be implementing a module on the Great Plains for fixed asset management. OHL requires software updates to accommodate the FIT and MicroFIT settlement and has budgeted $60,000 for this part of the project.

2010 Project: Purchase 1 Pick Up Truck and 1 Van

Cost: $65,000 1930-$65,000

Need: OHLs replacement schedule that is 7 years for small vehicles before they become costly to repair, uneconomic and unsafe to operate. The two trucks that require replacement are a 2003 pickup and a 2003 mini-van. OHL will obtain 3 different supplier quotes and select the best suited vehicle based on price.

APPENDIX A

CIS PRESENTATION TO BOARD OF DIRECTORS

Customer Service/Administration

Submitted to OHL Board of Directors by Ruth Tyrrell

CIS System Recommendation

With the recent decision regarding the merger between Orangeville Hydro and Westario I am now able to move forward with a recommendation for the new CIS system for the utility.

As noted in my last report, the recommendation is to move forward with the North Star (Harris) system under the Utility Collaborative Services Group (Midland, Centre Wellington and Parry Sound) along with Collus Power and Wasaga Electric Distribution.

The UCS business model provides Orangeville Hydro with a unique opportunity to become part of an environment which provides a stable operational foundation, and allows utilities to work together and benefit from collective buying pools and agreed upon standards related to their daily activities.
What makes the UCS business model distinctive from other vendors is that the UCS customers are actually the shareholders of the Company. By offering a technology solution in this manner, the “middle man” is eliminated from the equation which results in cost savings that are passed directly back to each owning utility. In addition to the financial benefits, the shareholders of the company are able to benefit from best practice business processes that are shared among the group. Aggregated pricing in the initial purchase of the software solution is a key feature of working with UCS; however, the hosting of the ASP Service that is part of the initiative provides an even greater value as the technical management of the system is part of the package offered by UCS.

Strategy of UCS

Ontario utilities have realized when they work as a group, they are able to more cost effectively achieve common goals, and this is evidenced by such successful working groups as Cornerstone Hydro Electric Concepts (CHEC), the Niagara Erie Power Alliance (NEPA), and the Upper Canada Energy Alliance (UCEA). As well as creating large buying pools to achieve preferential pricing where applicable, these working groups bring a united voice to the industry.

In 2006, three utilities (Centre Wellington, Midland & Parry Sound) came together with the goal of creating this type of environment, allowing utilities to work together and benefit from collective buying pools and standards related to their daily activities. The first step in this process was to create a model which would address the concerns that have gone unresolved in other ASP models in Ontario.

UCS Corporate Structure

Aggregate pricing models are achieved in UCS with the shareholder agreement providing long term commitment and cancellation clauses (3 Year). These terms protect the aggregate pricing being received by members. A Co-Op style service has proven to be a successful venture for another Harris Customer. Wisconsin Public Power Inc. (WPPI) is a 46 Member cooperative working in a shared service model that has benefited from group pricing for software and IT infrastructure. To meet the requirements of multiple shareholding utilities, as well as the regulator, the following considerations have been captured with the UCS Shareholder Agreement:

- No one distributor would have more than 49% ownership. Therefore no distributor would have the requisite amount of control to be considered an affiliate, as defined in *The Ontario Business Corporations Act*, of the Company.
- The Company will have one non-distributor shareholder, Util-Assist, which will act as the tie breaker in the event that the Board of Directors is unable to come to agreement.
- Distributor employees could be directors or officers of the Company, but not employees.

- Participating distributors must subscribe to, and receive, at least one service from the Company.
- Each owner in UCS has only one vote no matter what their size. This ensures that each utility maintains an equal voice.
- All pricing models are based on the aggregate volume of the corporation allowing the members to benefit from the group's buying power.
- The community of UCS customers benefit from the implementation of standards to aid in the daily operation, support and training of staff when it relates to their back office systems.
- Utilities will have the role of:
    - Owners (Benefiting from the success of the organization),
      Customers (Setting and monitoring the service level of the organization),
    - Voice (Provide Leadership relating to the direction of the Entity, and an Advocacy role to encourage other utilities to join the organization).
- Util-Assist Inc. acts as the Consulting firm for UCS, performing such services as:
    - Negotiation with Third Party Providers
    - Sales and Marketing for UCS Corporation
    - Provide staffing to members who request assistance.

The Current number of positions on the board is 6. Orangeville Hydro will hold a place on the board along with Wasaga Electric Distribution and Collus.

<u>UCS System Infrastructure</u>

I.T. Infrastructure/Server Solution

A third party contract will be entered into with ITM Hosting Services who currently host the infrastructure for the UCS Group.

The UCS solution provides a performance oriented, reliable, scalable and efficient package on which to operate NorthStar (Harris). Serviced by contracted "round-the-clock" IT Specialists, the ASP Model permits the deployment of varying technologies without the overhead of having to hire costly IT resources for each technology. The UCS model is an Application Specific Service that benefits from the experience and focus of those involved in the Model. By deploying, managing, and growing many Customers on the same platform, substantial savings can be realized in many areas from software/hardware development to ongoing care feeding and growth. The principle of the larger the quantity, the lower the cost to deploy and operate comes to fruition. All infrastructure devices are Enterprise Class components from industry leaders such as Cisco Systems, IBM, and Sun Microsystems that ensure maximum uptime, on screen performance, and Data Security/Availability. Dedicated Network Management Servers monitor and report on any problems encountered on a 7/24 basis.

Benefits of Outsourced solution

- Managed Services by Skilled Professionals
- Lower IT & Deployment Costs
- Simplified Processes to Manage and Execute
- Extended Capabilities
- Shorter Delivery Cycles

Data Centre

The housing facility is located in Newmarket, Ontario. It is outfitted with Enterprise Class infrastructure including 1000MB/s wiring & Fibre to the Desktops and Servers. A dedicated 3 Phase AC house feed keeps the Networking, Server, and environmental equipment away from House Breakers and the Online UPS and Diesel Generator combination maintain adequate AC to continue operations for approx 18 – 24 hours without Operator attendance, (required to refuel). Alarming tools are in place to notify us of any interruptions in the AC Power to which there would be immediate response. Off site we have 200 gallons of Diesel fuel available which would increase our runtime to some 72 hours without seeking commercial fuel.

Disaster Recovery

Disaster Recovery is an integral part of the UCS solution. The platform accommodates various recovery options up to and including a fully capable offsite Server. In today's environment the level of Disaster Recovery delivered is closely merged with the associated costs of that delivery. UCS offers two sites able to accommodate a recovery should the prime site fail. At both sites there are points of Internet connectivity with routers and related gear. Through Service Level Agreements there are quarterly tests to ensure the prescribed recovery facility is operational and ready.

Data Security

Data Security is really a matter of proper planning, implementing an access and security policy, and monitoring that policy to ensure it is being followed. There are numerous facilities on this platform to ensure the Data is safeguarded and made available only to those requiring access. UCS will work with us to first develop an access and security policy and then implement those guidelines providing quarterly feedback and reviews. The Virtual Private Network (VPN) and Internet Access is the first point of access concern. Cisco Firewalls, Routers, and VPN Devices are strategically placed to ensure only those permitted access to specific areas are granted access. A Syslog Server monitors activities (7/24) and reports problems to the Operator. As a member of Cert and several other Internet Security Organizations UCS is kept up to date on any issues that may arise. Where indicated, Virus Protection software is enabled with automatic updating and reporting on any deviations. UCS's track record is impressive with no Customers (to date) having sustained an attack by the numerous Worms and Viruses roaming the Internet. The actual Database provides multiple levels of Data protection. In addition to the Operating System upgrades and patches the OS allows UCS to control which users can read, write, and execute files on the Server. The next level is the Database itself where the Database Engine controls access to the core tables and resources. Lastly, there is a per user security facility that is granular enough to specify what modules within the Database are allowed to be accessed by a User.

UCS CIS Solution Partner - Harris Computer Corporation
Company Overview

Brief History

Harris commenced operations in 1976 when Nigel Harris formed the Company to provide software solutions to municipal governments in the province of Ontario. Nigel retained full ownership of the Company and he and several employees began business operations out of Ottawa. In 1984, Harris moved its focus away from tax-based management systems for Ontario-based municipalities and began its concentrating on utility billing and customer information solutions. Their first billing system was introduced in Ontario in the early 1990's and has continued to grow ever since. To fuel their growth Harris began to expand into the United States in 1995 in particular the Massachusetts area. Today they have over 5,000 customers, twenty-five offices, and over 560 employees. In 1996, Harris was purchased by Constellation Software Incorporated and expanded its efforts in gaining market share in the United States. The Ontario Municipal Employee Retirement Savings (OMERS) was at this time the majority shareholder and remains the largest single Constellation shareholder.

Harris Business Partners in Ontario

Harris is fortunate to have a number of very strong business partners in the Ontario electric market including Utility Collaborative Services. Each partner brings their own value add to Ontario LDC's and Harris fully supports them in their implementation efforts. Harris typically performs the data conversion for their partners and also supplements their delivery team in an almost seamless manner. This will become important as Orangeville Hydro moves from the evaluation to implementation phase as they have a significant number of direct and indirect implementation specialists familiar with the unique requirements of the Ontario electric market.

NorthStar Deregulation Module

Harris developed an integrated deregulation module and has been very responsive to the ongoing changes and reporting requirements of the Ontario market. It is fully compliant and the provincially mandated changes are covered by Support and Maintenance Agreements which means no unexpected or quarterly billing charges.

Settlement

The strategy has always been to develop solutions where they have domain expertise and work with partners when deemed they bring added value to the table. For settlement, Harris chose to work with settlement vendors versus developing our own settlement solution. They currently work with Utilismart Corporation, Kinetiq, and Peterborough. Each varies in the services they provide customers but all work equally well.

Spoke

Similar to settlement, Harris opted to work with partners such as SPi Group and Systrends that have domain expertise rather than develop this functionality within NorthStar.

Provincial MDM/R

Three of the five participants in the MDM/R working group are NorthStar customers.
Harris has been working with Newmarket Hydro, Milton, and Chatham-Kent Energy and NorthStar will be ready to work with the MDM/R when it is available. Many of their customers have been actively rolling out smart meters and Harris has already made changes to the application to accommodate the additional data and factored the roll-out of the provincial MDM/R into NorthStar development and can easily move from the current local data repository to the provincial repository. This also applies to the DSM module for displaying TOU information to end customers.

SMART Metering

Harris worked closely with its customers as they tested various smart meter technologies and actively participated in the Ontario Utilities Smart Meter Working Group. Harris' NorthStar customers are at the forefront of implementing smart meters and Harris made changes in their database structure in advance of the MDM/R to accommodate TOU readings and bill calculations. Three of their customers have converted from smart meter trials to full deployment.

Software for Life

Harris continually evolves flagship solutions by leveraging new technology and development tools to deliver new functionality and enhancements to their customers. To take advantage of these enhancements while minimizing the financial impact, Harris developed Software for Life policy. Software for Life provides all active customers with no-charge or reduced licenses to all major platform releases. For NorthStar, Software for Life has allowed our customers to evolve from version 4 in the 90's to version 6 today with minimal impact.

NorthStar CIS/billing

Harris has one of the most robust CIS/billing systems available in the industry. It has evolved over the last thirty-plus years through continual enhancements and modifications to include all aspects of billing and customer service. The CIS/billing system provides a single solution for tracking of all interaction with customers including consumption history, billing history, adjustments, credit history, meter inventory, premise and meter history, service order history, and more. Harris' CIS/billing system is extremely flexible and provides a high degree of integration with all the major handheld units. This integration also extends to integrating with other applications such as third-party accounting systems, external bill print organizations, credit bureaus, interactive voice response systems, and document management solutions. With Harris' CIS/billing systems we have the option of billing up to seventy-two separate metered or flat rate services. The solution also provides the flexibility for billing residents and organizations should you ultimately decide to perform billing services for neighboring communities.

Costing

Operational costs to UCS are based on 10,871 accounts for both Orangeville Hydro and Grand Valley, at $0.9885 per month equating to $128,951. per year plus approximately $5,000.00 for third party support for report writing software and SPI hub fees and maintenance.

Capital costs for both Orangeville Hydro and Grand Valley for any third party licenses, setup and conversions equates to $259,300.

File Nexus Solution

At this time, I would also like to consider the implementation of a document management system, "File Nexus".

Our current file management system is very antiquated and there have not been a lot of options for replacement. Under the UCS umbrella we have an opportunity to obtain a program that integrates with the new CIS software and can also work with all document management within Orangeville Hydro.

Benefits of document management are as follows:

- Opportunity for future system integrations
    - E-billing options
    - Integration of ESA documents
    - Integration of remittance stubs
    - Cheque scanning

- Deployment of customer bills in pdf format allowing CSRs to view the same bill as the customer receives
- Current technology permits virtually all and any documents to be indexed, catalogued and retrieved
- Reduce photocopying costs
- Some interesting corporate facts:
    - 7.5% of all documents get lost
    - 3% of all documents get misfiled
    - Only 10% of corporate information rests in structured filing means
    - An average office spends $120 finding a misfiled document and $250 creating it
    - Only 1 in 10 pages printed is ever consulted again.

File Nexus – Co-op Model

- File Nexus to be licensed in an ASP model using Loris Enterprise Licensing and delivered in a hosted configuration
- Each LDC that buys into the co-op with UCS will have full autonomy as far as access, indexing plans, storage and users
- With multiple LDCs sharing the platform the File Nexus product becomes cost attractive
- Added modules benefit all users
- Significant savings in scalability, reliability and presentment
- As additional LDCs come on board costs decrease on per LDC basis
- Could use a credit back to existing LDCs based on shared licensing costs

Costing

Based on 4 LDCs participating on year one the capital outset will be $54,103 and operational $27,107. As more LDCs sign on the costs reduce. There are a number of LDCs that are looking into joining UCS in order to access the cost savings for this particular product.

NOTE**This is a projection based on 4 LDCs and may have to be carried over to the new year as CIS implementation is a priority.

ASSET MANAGEMENT PLAN SUMMARY:

OHL is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. OHL distribution assets range in age from new to over 60 years old.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of OHL's physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates as demonstrated in Exhibit 2, Tab 3, Schedule 5. OHL does not have a formal asset management plan. For this first stage in developing an asset management plan, we contracted Hatch and Associates to assist by doing a comprehensive review and analysis of current asset condition. Accompanying this Schedule as Appendix A is a September 8, 2009 document titled "Asset Management Executive Summary Report". The findings of the Asset Management Condition Assessment Report will be used as a guideline to determine the short-term capital expenditure levels until there is more work completed on the data and asset management strategies contained within an Asset Management Plan. This report contains analysis of overall asset condition and assisted OHL in determining our 2010 and 2011 capital expenditures. It is important to note that OHL's formal Asset Management Plan is in its early development stage and in 2010 we will implement a GIS system and will perform a system optimization study. OHL will use the results of our future study along with the recent condition assessment to help us effectively plan capital and maintenance sustainment work programs.

The plan for Substation assets is currently under investigation by OHL to determine its context with respect to the strategy for the conversion of distribution system overhead and underground

4.16 kV line assets to 27.6 kV thus allowing for a further reduction of the four remaining municipal substations.

OHL has provided the forecast above for 2010 capital expenditures and the forecast for 2011 and 2012 are found in Table 1 and Table 2 below. The annual replacement costs, found in Table 1 and Table 2 are engineering estimates only and the actual expenditure levels in the capital budgets could be adjusted based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.).

Table 1

2011 Engineering Budget Forecast

Description	Forecasted Cost
27.6kV Conversion	$ 250,000.00
27.6kV Mechanized Scada Mate Switches	$ 32,000.00
Pole Replacement	$ 80,000.00
44kV Mechanized Altdi-Ruptor Switches	$ 31,000.00
Utility Relocates	$ 20,000.00
Infrastructure Betterments	$ 50,000.00
Remote Sensing	$ 30,000.00
Overhead and Underground Transformers	$ 60,000.00
Overhead and Underground Servicing	$ 50,000.00
Economic Evaluation-Orangeville Highlands	$ 150,000.00
Transportation Equipment - Two New Trucks	$ 80,000.00
Tools - Shop and Garage Equipment	$ 2,500.00
Measurement and Testing Equipment	$ 2,500.00
Motorized PME	$ 63,000.00
In Home Controls	$ 44,000.00
FIT Enablement-Meters and Services	$ 100,000.00
TOTAL	**$ 1,045,000.00**

1 **Table 2**

2012 Engineering Budget Forecast	
Description	**Forecasted Cost**
27.6kV Conversion	$ 250,000.00
27.6kV Mechanized Scada Mate Switches	$ 32,000.00
Pole Replacement	$ 100,000.00
44kV Mechanized Altdi-Ruptor Switches	$ 31,000.00
Utility Relocates	$ 20,000.00
Infrastructure Betterments	$ 50,000.00
Remote Sensing	$ 30,000.00
Overhead and Underground Transformers	$ 60,000.00
Overhead and Underground Servicing	$ 50,000.00
Economic Evaluation-Edgewood Valley	$ 70,000.00
Transportation Equipment - New Digger Derrick Purchase	$ 250,000.00
Tools - Shop and Garage Equipment	$ 2,500.00
Measurement and Testing Equipment	$ 2,500.00
Motorized PME	$ 63,000.00
In Home Controls	$ 44,000.00
FIT Enablement-Meters and Services	$ 100,000.00
TOTAL	**$ 1,155,000.00**

2

Appendix B

OHL Executive Summary Asset Condition Summary

Executive Summary

E.1 Introduction

Orangeville Hydro has completed an Asset Condition Assessment of its distribution assets, and summarized the results in this document. By using existing data, and supplementing it with additional data from field visits, it was possible to complete an objective appraisal of asset condition. In some cases, additional data will be required to achieve critical mass of asset condition data needed to effectively plan its sustainment work programs.

This report contains a review of the overall asset condition assessment process adopted by Orangeville Hydro, and documents the evaluated condition of the total population of Distribution assets, based on condition criteria and end-of-life criteria that are indicative of asset condition and consistent with industry practices.

The Distribution assets were grouped into 19 asset classes. Asset classes are further grouped into (a) Overhead, (b) underground, (c) substation, and (d) Other assets.

This report has been prepared by Hatch Ltd (Oakville, formerly Acres International Limited (Acres) of Oakville Ontario). The analysis and report has been prepared in consultation with Orangeville Hydro staff specialists, but the report and its conclusions are based on the findings of the consultant.

E.2 Process Review

In general, it has been found that Orangeville Hydro has undertaken a careful and thoughtful evaluation of condition assessment needs. Prior to the project resulting in this report, Orangeville Hydro has collected data on its major assets. During this project, additional data was collected to secure much of the information needed to assess the condition of its Distribution assets. The data collection methods, tools and technologies are generally appropriate to the task of measuring asset condition, providing the right data at an appropriate cost. The methods used by Orangeville Hydro have been found to be consistent with industry practices. The methods and procedures for data collection are documented for data collection practices by internal staff.

With a few exceptions, the identified data collection procedures have been executed according to specifications, and useable data has been collected and stored in databases.

Orangeville Hydro is using this data appropriately, having adopted condition criteria that form a rational basis for asset decision-making. Orangeville Hydro has adopted methods of analysis that are consistent with industry practices. With the adoption of composite Health Indices for each class of assets, as recommended by the consultant, Orangeville Hydro has established a coherent and rational basis for evaluating the overall condition of each Distribution asset owned by the company.

Tables E1 shows an overall evaluation of the quality of the processes adopted by Orangeville Hydro, and the quality of the data found in the various databases.

Category	Description	Count	UOM	Utility Comparison	Process Viability	Data Availability	Health Index Evaluated
Overhead							
2.1	Distribution Line Sections	56.0	km	2	2	2	Y
2.2	Load Break Switches	12.0	pc	3	2	3	Y
2.3	In-Line Switches	312.0	pc	1	1	1	Y
2.4	Pole Mounted Transformers	596.0	pc	1	1	3	Y
2.5	Fault Indicators	30.0	pc	3	2	1	Y
2.6	Fuse Cutouts	unknown		5	5	5	N
2.7	Voltage Conversion Transformers	5.0	pc	1	1	1	Y
Underground							
3.1	underground cable	381.0	pc	2	2	2	Y
3.2	pad mounted switchgear	60.0	pc	2	2	3	Y
3.3	pad mounted transformers	823.0	pc	1	1	3	Y
3.4	duct banks and manholes	unknown		5	5	5	N
Substations							
4.1	substation transformer (44-4kV)	8.0	pc	1	1	1	Y
4.2	substation switchgear	11.0	pc	1	1	3	Y
4.3	substation riser cable	33.0	pc	1	1	3	Y
4.4	substation HV structure	4.0	pc	1	1	3	Y
4.5	substation civil	4.0	pc	1	1	1	Y
Other Assets							
5.1	Metering	N/A					N
5.2	Right of Way	unknown		3	3	5	N
5.3	Operating Spares	N/A		1	1		N
5.4	Other Assets not Included	N/A					N

⬜	not evaluated
🟩	1-2 very good - only minor gaps or problems
🟨	3 fair - some gaps or problems
🟥	4-5 very poor - significant gaps or problems

Table E1 - Evaluation of Orangeville Hydro ACA Processes for P1 Assets

Orangeville Hydro is pursuing a program of asset condition assessment that is equivalent to programs executed in forward-thinking utilities around the world. The ACA processes of Orangeville Hydro have been demonstrated to be viable, in the sense that the data collected and the uses made of it are entirely appropriate to support the spending decisions that Orangeville Hydro must make.

Composite Health Indices have been recommended for Orangeville Hydro use by the consultant in every case. Health Indices provide a basis for assessing the overall health of an asset. Health Indices are based on identification of the modes of failure for the asset and its sub-systems, as well as functional obsolescence drivers, and then developing measures of generalized degradation or degradation of key sub-systems that can lead to end-of-life for the entire asset.

The data availability rankings require some clarification. The only assets ranked “poor” on this aspect were for fuse cutouts, duct banks and Right of Way.

The most common way of managing fuse cutouts is on a run-to-failure basis and can be easily replaced. These fuse cutouts are understood as those that are not associated with transformers and not associated with cable risers. These devices are used for switching, isolation and feeder tap protection.

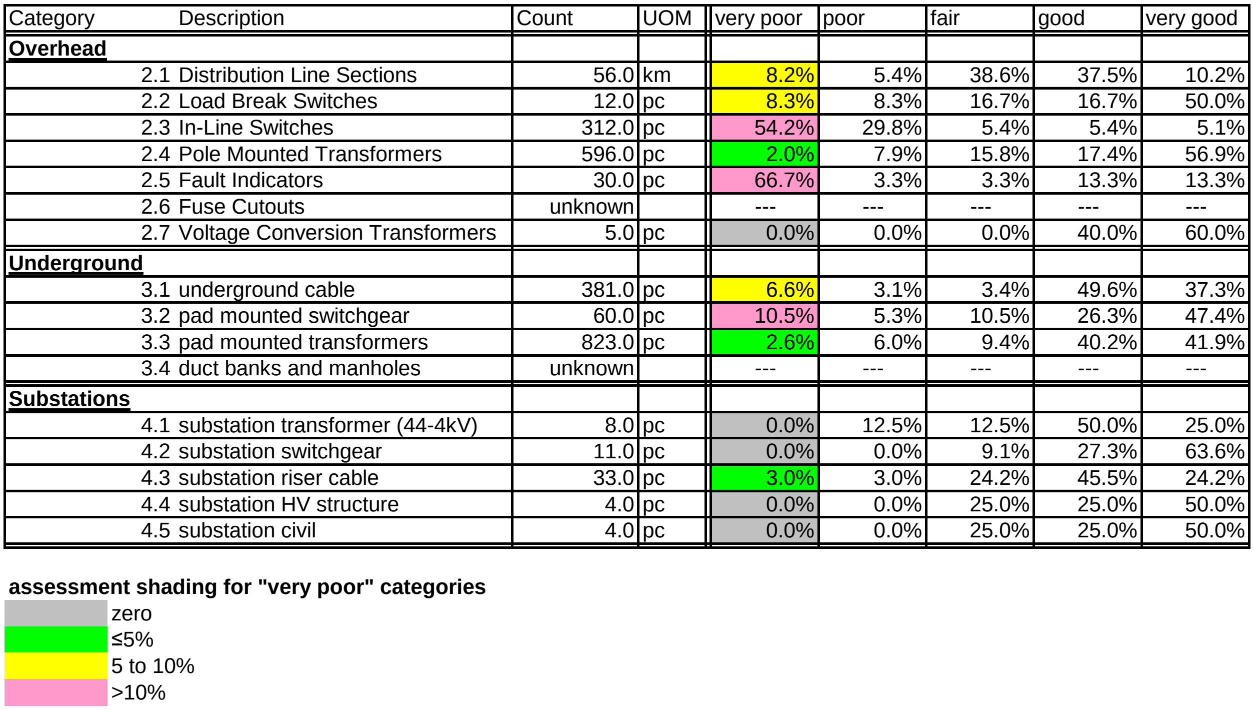
For Duct Banks and Right of Way, It is recommended that Orangeville Hydro review their process and data collection methods, both for demographics and for condition.

Most key performance indicators are in good or very good condition. Those flagged as fair can be improved with some changes to process and/or data collection practices.

E.3 Asset Condition Results

The condition of the Orangeville Hydro assets has been evaluated in all circumstances where viable condition criteria are in place and sufficient condition data exists. Health Indices have been calculated for every asset with a recommended Health Index formulation and sufficient condition data to satisfy the minimum requirements for application of that formulation.

The results of the asset condition assessments assets are presented in Tables E2, based on the Health Index formulations and the extrapolated test results..



Category	Description	Count	UOM	very poor	poor	fair	good	very good
Overhead								
2.1	Distribution Line Sections	56.0	km	8.2%	5.4%	38.6%	37.5%	10.2%
2.2	Load Break Switches	12.0	pc	8.3%	8.3%	16.7%	16.7%	50.0%
2.3	In-Line Switches	312.0	pc	54.2%	29.8%	5.4%	5.4%	5.1%
2.4	Pole Mounted Transformers	596.0	pc	2.0%	7.9%	15.8%	17.4%	56.9%
2.5	Fault Indicators	30.0	pc	66.7%	3.3%	3.3%	13.3%	13.3%
2.6	Fuse Cutouts	unknown		---	---	---	---	---
2.7	Voltage Conversion Transformers	5.0	pc	0.0%	0.0%	0.0%	40.0%	60.0%
Underground								
3.1	underground cable	381.0	pc	6.6%	3.1%	3.4%	49.6%	37.3%
3.2	pad mounted switchgear	60.0	pc	10.5%	5.3%	10.5%	26.3%	47.4%
3.3	pad mounted transformers	823.0	pc	2.6%	6.0%	9.4%	40.2%	41.9%
3.4	duct banks and manholes	unknown		---	---	---	---	---
Substations								
4.1	substation transformer (44-4kV)	8.0	pc	0.0%	12.5%	12.5%	50.0%	25.0%
4.2	substation switchgear	11.0	pc	0.0%	0.0%	9.1%	27.3%	63.6%
4.3	substation riser cable	33.0	pc	3.0%	3.0%	24.2%	45.5%	24.2%
4.4	substation HV structure	4.0	pc	0.0%	0.0%	25.0%	25.0%	50.0%
4.5	substation civil	4.0	pc	0.0%	0.0%	25.0%	25.0%	50.0%

assessment shading for "very poor" categories

⬜	zero
🟩	≤5%
🟨	5 to 10%
🟥	>10%

Table E2 – Summary of ACA Condition Results

For some assets, maintenance and condition data has been collected for virtually every asset owned by Orangeville Hydro. In other asset classes, a smaller proportion of the total asset base has been tested and/or inspected, and the size and nature of the samples taken is sufficient to extend the results to the balance of the assets in that class through statistically relevant sampling.

A consistent approach has been used in developing the Health Index formulations, so that the meaning of the categories is broadly consistent across most assets.

In general terms, a "Very Poor" asset can be interpreted to be very close to end-of-life, requiring urgent attention in the form of a risk assessment potentially leading to asset replacement or a major overhaul. Assets in the "Poor" category can be interpreted as being close to end-of-life, requiring risk assessment potentially leading to replacement or significant maintenance expenditures in a 1 to 5-year time frame. Assets in "Fair" condition have experienced significant deterioration, but may be able to survive for another 5-10 years with only modest maintenance and/or component replacements. Assets in the "Good" category can be considered to have at least 10 to 20 years of service left, given normal maintenance expenditures. Assets in the "Very Good" category should survive for more than 20 years, given normal maintenance expenditures. This scale is based on assets that typically have a 20 – 40 year life span. Assets with a shorter lifespan, have shorter time periods for each

As might be expected, the vast majority of the assets owned by Orangeville Hydro are ranked in "Good" or "Very Good" condition, meaning that these assets are generally being managed effectively and are being maintained in a condition suitable for many more years of service. The same conclusion may be drawn from the relatively small proportion of assets found in "Very Poor" or "Poor" condition.

In the Orangeville Hydro Fleet of Assets, the following assets have shown noticeably higher than average results (red colour) in the very poor condition: in-line switches, fault indicators, and pad mount switchgear. In addition, higher than expected levels (yellow) were found in distribution line sections, load break switches and underground cable.

Regarding in line switches, some of the data records were incomplete and it was unknown if the switch was operated successfully within the last 2 years; additional data collection is underway to refine results. Both fault indicators and pad mounted switchgear have particular manufacturers and/or other physical characteristics such that the devices are no longer suitable for operations environment at Orangeville Hydro; consequently, it has been decided that electrical equipment with these characteristics is functionally obsolete.

Concerns exist for distribution line sections, load break switches and underground cable. For load break switches, there was marginal volume of information available. It is recommended that a short term maintenance program be implemented to acquire all required condition data. Distribution line sections and underground cable both have circuit sections that have been identified for conversion from 4kV to 27kV. For Distribution line sections, there are several examples of older construction, which does not meet the present engineering standard. In the last 10 years, the engineering standard has changed to armless construction, with pole mounted equipment between phase wire and neutral. Upgrading these line sections, or replacing transformers presents Orangeville Hydro with some technical challenges, consequently, the line sections have been identified as functionally obsolete. Overall, both distribution line sections and underground cable are well managed.

CAPITALIZATION POLICY:

POLICY STATEMENT & PURPOSE

It is the policy of the company to maintain strong financial control over expenditures for capital assets by evaluating and approving capital requests for projects that enhance or improve the efficiency of the Company's assets. The policy describes the process used for determining if expenditures should be capitalized or expensed. A materiality amount is used and any expenditure below that threshold will be expensed to operations in the current year.

GUIDELINES

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A "betterment" is a cost which enhances the service potential of a capital asset and is therefore capitalized. A "betterment" includes increasing the capacity of the asset, lowering associated operating costs, improving the quality of output or extending the asset useful life. This enhancement can result in an increase in physical output or service capacity, a decrease to operating costs, extension of the useful life of the asset, or improvement in the quality of the asset's output. Service potential may be enhanced when there is an increase in physical output or service capacity, associated operating costs are lowered, the useful life is extended, or the quality of output is improved. For example a refurbished transformer in which the service potential has been enhanced should be capitalized. Further, if during an underground fault repair, the work results in a reconfiguration of the asset that will clearly benefit future periods, there may be an argument to capitalize the work.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

MATERIALITY

All additions to capital assets and betterments will be capitalized subject to materiality limits as set out in this policy. At times the administrative costs of capitalizing an asset may outweigh the intended benefits. While the expenditure may meet the definition to qualify as a capital asset, a level is set, which if an expenditure falls below, it is not capitalized but charge to expense in the current period. This level is known as a materiality limit.

Materiality Limits

Identifiable Assets

Distribution Plant	$ 1,000
General Plant	$ 1,000

Grouped Assets

Distribution Plant	$ 1,000
General Plant	$ 500 (only if total of group is over this amount)

Identifiable Assets

An identifiable capital asset is an asset that has a sufficiently high unit cost and is easily identifiable for the asset to be individually tracked and recorded.

Grouped Assets

For efficiency, capital assets may be grouped if, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a pool for the purposes of amortization.

CAPITAL ASSET RECORDS

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost.

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

Amortization

Capital assets are generally amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry. Large and unique capital expenditures will be reviewed on an individual basis to determine the expected life and appropriate method of depreciation.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

Extraordinary Items

Extraordinary items will be identified separately provided they exceed the materiality threshold established by the OEB. There may be instances where the cost of a non-capital expenditure may be deferred or in effect capitalized. For example a major infrequent repair on an existing asset, a regulatory process resulting in a major cost to the operating plant without actual replacement or betterment, and repairs to property loss resulting from extraordinary events such as an ice storm are costs which may be eligible for deferment. Recovery of extraordinary items through rates as a "Z" Factor expense will follow OEB guidelines.

POLICY COMPLIANCE

All current practices will comply with OEB Accounting Procedures Handbook and the CICA Handbook. Employees must report incidents of non-compliance relating to this policy in a timely manner to the Policy Owner. Non-compliance of a serious nature will be immediately reported to the President Determination of non-compliance issues of a serious nature will be the responsibility of the Policy Owner.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

OHL tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding Hydro One related incidents. The following table shows actual results for the past three years. As indicated in the chart below, OHL's 2006, 2007 and 2008 reliability performance is within acceptable levels.

OHL is committed to the reliability of the distribution system. The result of our asset condition assessment has given OHL a better understanding of the areas of concern to target and prioritize for future capital and maintenance programs. OHL will continue making capital investments in infrastructure to maintain our current reliability levels.

A previous review of OHL's reliability SQI's during the years 2002 to 2006 indicated that the most frequent cause of outages after scheduled outages (Interruption Code 1 in OEB Reporting) was defective equipment (Interruption Code 5). Defective equipment outages are primarily due to age and condition, lightning strikes or other weather related phenomenon. A further review of the reliability statistics indicates the most frequent equipment failures are underground cables and transformers (the highest percentage of transformer failures occurs on the underground system), with underground cables responsible for the most customer outage hours. The second highest number of customer outage hours relating to defective equipment is associated with overhead conductors and switches.

	2006		2007		2008	
	Excluding Hydro One	Total System	Excluding Hydro One	Total System	Excluding Hydro One	Total System
SAIDI	0.86	2.16	1.50	2.99	1.51	1.51
SAIFI	1.07	1.83	1.15	1.64	1.09	1.09
CAIDI	0.81	1.18	1.31	1.82	1.39	1.39

WORKING CAPITAL CALCULATION:

Overview:

OHL’s working capital allowance is forecast to be $3,365,329 for 2010 and is based on the “15% of specific OM&A accounts formula approach” referred to at page 15 of the Board's Filing Requirements. OHL has provided its calculations by account for each of 2006 Actual, 2007 Actual, the 2009 Bridge Year and the 2010 Test Year in Table 1 on the following pages. OHL has provided a spreadsheet setting out OHL’s Cost of Power calculations as Appendix A to this Schedule.

Table 1
Working Capital Calculation by Account

Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Actual	Allowance for Working Capital	2009 Bridge	Allowance for Working Capital	2010 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%		15%
Operation										
5005-Operation Supervision and Engineering	0	0	0	0	0	0	0	0	0	0
5010-Load Dispatching	0	0	0	0	0	0	0	0	0	0
5012-Station Buildings and Fixtures Expense	0	0	0	0	0	0	0	0	0	0
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	659	99	861	129	171	26	1,028	154	1,013	152
5017-Distribution Station Equipment - Operation Supplies and Expenses	47,344	7,102	30,842	4,626	48,558	7,284	64,698	9,705	66,355	9,953
5020-Overhead Distribution Lines and Feeders - Operation Labour	2,078	312	3,785	568	3,242	486	3,652	548	3,758	564
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expense	174	26	0	0	1,607	241	1,080	162	1,080	162
5030-Overhead Sub transmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	0	0	769	115	1,108	166	3,422	513	3,558	534
5040-Underground Distribution Lines and Feeders - Operation Labour	1,241	186	585	88	1,119	168	475	71	1,492	224
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expen	548	82	23	3	242	36	180	27	270	41
5050-Underground Sub transmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	878	132	378	57	986	148	676	101	694	104
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0	0	0
5065-Meter Expense	74,472	11,171	111,882	16,782	86,151	12,923	90,292	13,544	103,931	15,590
5070-Customer Premises - Operation Labour	46,539	6,981	62,348	9,352	49,285	7,393	39,742	5,961	44,701	6,705
5075-Customer Premises - Materials and Expenses	29,011	4,352	17,998	2,700	14,660	2,199	18,098	2,715	19,505	2,926
5085-Miscellaneous Distribution Expense	39,128	5,869	34,186	5,128	124,310	18,646	89,723	13,458	156,263	23,439
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0	0	0	0	0
5096-Other Rent	6,736	1,010	7,489	1,123	7,482	1,122	6,325	949	6,325	949
Sub-Total	**248,806**	**37,321**	**271,145**	**40,672**	**338,920**	**50,838**	**319,390**	**47,908**	**408,946**	**61,342**
Maintenance										
5105-Maintenance Supervision and Engineering	53,982	8,097	66,908	10,036	90,555	13,583	122,585	18,388	128,570	19,286
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	(36,345)	(5,452)	1,733	260	18,743	2,811	11,091	1,664	11,345	1,702
5120-Maintenance of Poles, Towers and Fixtures	44,245	6,637	36,482	5,472	27,160	4,074	19,983	2,997	23,374	3,506
5125-Maintenance of Overhead Conductors and Devices	75,188	11,278	79,905	11,986	83,883	12,582	63,242	9,486	69,136	10,370
5130-Maintenance of Overhead Services	25,292	3,794	27,582	4,137	26,555	3,983	12,571	1,886	19,169	2,875
5135-Overhead Distribution Lines and Feeders - Right of Way	67,756	10,163	51,671	7,751	115,788	17,368	98,825	14,824	104,245	15,637
5145-Maintenance of Underground Conduit	46	7	798	120	0	0	0	0	0	0
5150-Maintenance of Underground Conductors and Devices	17,290	2,594	21,924	3,289	8,329	1,249	7,681	1,152	10,732	1,610
5155-Maintenance of Underground Services	49,114	7,367	84,201	12,630	68,555	10,283	75,872	11,381	80,437	12,066
5160-Maintenance of Line Transformers	29,632	4,445	70,325	10,549	17,313	2,597	35,826	5,374	45,413	6,812
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour	1,513	227	3,229	484	894	134	0	0	0	0
5172-Sentinel Lights - Materials and Expenses	928	139	723	108	225	34	0	0	0	0
5175-Maintenance of Meters	10,727	1,609	0	0	0	0	0	0	0	0
5178-Customer Installations Expenses- Leased Property	0	0	0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0	0	0
Sub-Total	**339,366**	**50,905**	**445,480**	**66,822**	**457,999**	**68,700**	**447,677**	**67,152**	**492,423**	**73,863**

Billing and Collections														
5305-Supervision	28,970	4,346		29,768	4,465		30,942	4,641		24,493	3,674		26,093	3,914
5310-Meter Reading Expense	92,682	13,902		98,765	14,815		97,875	14,681		112,253	16,838		114,976	17,246
5315-Customer Billing	186,772	28,016		192,648	28,897		210,800	31,620		209,046	31,357		238,412	35,762
5320-Collecting	122,015	18,302		128,939	19,341		137,665	20,650		142,867	21,430		160,472	24,071
5325-Collecting- Cash Over and Short	178	27		(123)	(18)		(485)	(73)		0	0		0	0
5330-Collection Charges	0	0		0	0		0	0		0	0		0	0
5335-Bad Debt Expense	46,042	6,906		33,590	5,038		24,916	3,737		20,000	3,000		20,000	3,000
5340-Miscellaneous Customer Accounts Expenses	0	0		0	0		0	0		0	0		0	0
Sub-Total	**476,660**	**71,499**		**483,587**	**72,538**		**501,713**	**75,257**		**508,659**	**76,299**		**559,953**	**83,993**
Community Relations														
5405-Supervision	0	0		0	0		0	0		0	0		0	0
5410-Community Relations - Sundry	48,971	7,346		23,610	3,541		23,856	3,578		12,584	1,888		28,862	4,329
5415-Energy Conservation	102,620	15,393		144,721	21,708		18,695	2,804		0	0		0	0
5420-Community Safety Program	0	0		0	0		0	0		0	0		0	0
5425-Miscellaneous Customer Service and Informational Expenses	0	0		0	0		0	0		0	0		0	0
5505-Supervision	0	0		0	0		0	0		0	0		0	0
5510-Demonstrating and Selling Expense	0	0		0	0		0	0		0	0		0	0
5515-Advertising Expense	0	0		0	0		0	0		0	0		0	0
5520-Miscellaneous Sales Expense	0	0		0	0		0	0		0	0		0	0
Sub-Total	**151,591**	**22,739**		**168,331**	**25,250**		**42,551**	**6,383**		**12,584**	**1,888**		**28,862**	**4,329**
Administrative and General Expenses														
5605-Executive Salaries and Expenses	211,213	31,682		217,188	32,578		250,260	37,539		357,898	53,685		386,005	57,901
5610-Management Salaries and Expenses	144,703	21,705		157,627	23,644		153,939	23,091		129,183	19,378		132,149	19,822
5615-General Administrative Salaries and Expenses	55,885	8,383		101,281	15,192		134,014	20,102		182,252	27,338		270,196	40,529
5620-Office Supplies and Expenses	60,361	9,054		43,213	6,482		46,635	6,995		47,081	7,062		53,799	8,070
5625-Administrative Expense Transferred Credit	0	0		0	0		0	0		0	0		0	0
5630-Outside Services Employed	194,404	29,161		183,497	27,525		227,331	34,100		97,639	14,646		123,329	18,499
5635-Property Insurance	6,600	990		9,762	1,464		21,046	3,157		22,342	3,351		26,412	3,962
5640-Injuries and Damages	16,079	2,412		21,508	3,226		22,654	3,398		19,856	2,978		20,253	3,038
5645-Employee Pensions and Benefits	30,899	4,635		31,638	4,746		43,881	6,582		38,343	5,751		37,330	5,600
5650-Franchise Requirements	0	0		0	0		0	0		0	0		0	0
5655-Regulatory Expenses	8,456	1,268		39,549	5,932		44,408	6,661		40,807	6,121		77,072	11,561
5660-General Advertising Expenses	911	137		1,090	164		0	0		0	0		0	0
5665-Miscellaneous General Expenses	50,480	7,572		58,188	8,728		43,605	6,541		70,226	10,534		74,656	11,198
5670-Rent	2,450	368		0	0		0	0		0	0		0	0
5675-Maintenance of General Plant	66,178	9,927		72,050	10,808		79,173	11,876		75,259	11,289		77,632	11,645
5680-Electrical Safety Authority Fees	1,609	241		0	0		0	0		0	0		0	0
5685-Independent Market Operator Fees and Penalties	0	0		0	0		0	0		0	0		0	0
Sub-Total	**850,229**	**127,534**		**936,592**	**140,489**		**1,066,947**	**160,042**		**1,080,885**	**162,133**		**1,278,832**	**191,825**
Cost of Power														
4705-Power Purchased	14,450,334	2,167,550		15,032,932	2,254,940		14,671,157	2,200,674		15,926,149	2,388,922		15,828,613	2,374,292
4708-Charges-WMS	1,317,369	197,605		1,343,186	201,478		1,483,174	222,476		1,704,874	255,731		1,694,433	254,165
4710-Cost of Power Adjustments	0	0		0	0		0	0		0	0		0	0
4712-Charges-One-Time	0	0		0	0		0	0		0	0		0	0
4714-Charges-NW	1,326,739	199,011		1,298,958	194,844		1,049,109	157,366		1,245,758	186,864		1,235,637	185,346
4716-Charges-CN	0	0		704,377	105,657		670,819	100,623		723,777	108,567		702,316	105,347
4730-Rural Rate Assistance Expense	705,941	105,891		0	0		0	0		0	0		0	0
4750-LV Charges	0	0		352,871	52,931		340,979	51,147		318,879	47,832		205,513	30,827
Sub-Total	**17,800,382**	**2,670,057**		**18,732,324**	**2,809,849**		**18,215,238**	**2,732,286**		**19,919,438**	**2,987,916**		**19,666,513**	**2,949,977**
WORKING CAPITAL ALLOWANCE TOTAL	**19,867,035**	**2,980,055**	**0**	**21,037,459**	**3,155,619**	**0**	**20,623,368**	**3,093,505**	**0**	**22,288,633**	**3,343,295**	**0**	**22,435,528**	**3,365,329**

APPENDIX C

2009 COST OF POWER FORECAST CALCULATION

Electricity - Commodity	**2009 Forecasted Metered kWhs**	**2000 Loss Factor**			
Class per Load Forecast			**2009**		
Residential	85,073,410	1.0406	88,527,391	$0.0607	$5,375,383
Street Lighting	1,766,075	1.0406	1,837,778	$0.0607	$111,590
Sentinel Lighting	129,305	1.0406	134,555	$0.0607	$8,170
GS<50kW	38,776,135	1.0406	40,350,446	$0.0607	$2,450,079
GS>50kW	125,942,329	1.0406	131,055,588	$0.0607	$7,957,695
Unmetered Scattered Load	367,676	1.0406	382,604	$0.0607	$23,232
TOTAL	**252,054,931**		**261,905,757**		**$15,926,149**

Transmission - Network		**Volume Metric**			
Class per Load Forecast			**2009**		
Residential		kWh	88,527,391	$0.0052	$460,342
Street Lighting		kW	5009	$1.4605	$7,316
Sentinel Lighting		kW	358	$1.4678	$526
GS<50kW		kWh	40,350,446	$0.0048	$193,682
GS>50kW		kW	300,571	$1.9365	$582,056
Unmetered Scattered Load		kWh	382,604	$0.0048	$1,836
TOTAL					**$1,245,758**

Transmission - Connection		**Volume Metric**			
Class per Load Forecast			**2009**		
Residential		kWh	88,527,391	$0.0031	$274,435
Street Lighting		kW	5,009	$0.8505	$4,260
Sentinel Lighting		kW	358	$0.8684	$311
GS<50kW		kWh	40,350,446	$0.0028	$112,981
GS>50kW		kW	300,571	$1.1003	$330,718
Unmetered Scattered Load		kWh	382,604	$0.0028	$1,071
TOTAL					**$723,777**

Wholesale Market Service/RRA					
Class per Load Forecast			**2009**		
Residential			88,527,391	$0.0065	$575,428
Street Lighting			1,837,778	$0.0065	$11,946
Sentinel Lighting			134,555	$0.0065	$875
GS<50kW			40,350,446	$0.0065	$262,278
GS>50kW			131,055,588	$0.0065	$851,861
Unmetered Scattered Load			382,604	$0.0065	$2,487
TOTAL					**$1,704,874**

Low Voltage					
Class per Load Forecast			**2009**		
Residential		kWh	88,527,391	$0.0013	$115,086
Street Lighting		kW	5,009	$0.3659	$1,833
Sentinel Lighting		kW	358	$0.3754	$134
GS<50kW		kWh	40,350,446	$0.0013	$52,456
GS>50kW		kW	300,571	$0.4953	$148,873
Unmetered Scattered Load		kWh	382,604	$0.0013	$497
TOTAL					**$318,879**

	2009
4705-Power Purchased	$15,926,149
4708-Charges-WMS	$1,704,874
4714-Charges-NW	$1,245,758
4716-Charges-CN	$723,777
4750-Low Voltage	$318,879
TOTAL	**19,919,438**

2010 COST OF POWER FORECAST CALCULATION:

Electricity - Commodity **Class per Load Forecast**	**2010 Forecasted Metered kWhs**	**2010 Loss Factor**	**2010**		
Residential	84,928,233	1.0468	88,902,303	$0.0607	$5,398,148
Street Lighting	1,798,732	1.0468	1,882,900	$0.0607	$114,330
Sentinel Lighting	129,899	1.0468	135,978	$0.0607	$8,257
GS<50kW	38,954,924	1.0468	40,777,752	$0.0607	$2,476,025
GS>50kW	122,840,423	1.0468	128,588,529	$0.0607	$7,807,895
Unmetered Scattered Load	376,928	1.0468	394,566	$0.0607	$23,958
TOTAL	**249,029,139**		**260,287,461**		**$15,828,613**

Transmission - Network **Class per Load Forecast**		**Volume Metric**	**2010**		
Residential		kWh	88,902,303	$0.0052	$462,292
Street Lighting		kW	5,102	$1.4605	$7,451
Sentinel Lighting		kW	360	$1.4678	$528
GS<50kW		kWh	40,777,752	$0.0048	$195,733
GS>50kW		kW	293,178	$1.9365	$567,739
Unmetered Scattered Load		kWh	394,566	$0.0048	$1,894
TOTAL					**$1,235,637**

Transmission - Connection **Class per Load Forecast**		**Volume Metric**	**2010**		
Residential		kWh	88,902,303	$0.0030	$269,534
Street Lighting		kW	5,102	$0.8318	$4,244
Sentinel Lighting		kW	360	$0.8493	$306
GS<50kW		kWh	40,777,752	$0.0027	$111,666
GS>50kW		kW	293,178	$1.0761	$315,487
Unmetered Scattered Load		kWh	394,566	$0.0027	$1,080
TOTAL					**$702,316**

Wholesale Market Service/RRA **Class per Load Forecast**			**2010**		
Residential			88,902,303	$0.0065	$577,865
Street Lighting			1,882,900	$0.0065	$12,239
Sentinel Lighting			135,978	$0.0065	$884
GS<50kW			40,777,752	$0.0065	$265,055
GS>50kW			128,588,529	$0.0065	$835,825
Unmetered Scattered Load			394,566	$0.0065	$2,565
TOTAL					**$1,694,433**

Low Voltage **Class per Load Forecast**			**2010**		
Residential		kWh	88,902,303	$0.0009	$78,872
Street Lighting		kW	5,102	$0.2434	$1,242
Sentinel Lighting		kW	360	$0.2485	$89
GS<50kW		kWh	40,777,752	$0.0008	$32,676
GS>50kW		kW	293,178	$0.3149	$92,318
Unmetered Scattered Load		kWh	394,566	$0.0008	$316
TOTAL					**$205,513**

	2010
4705-Power Purchased	$15,828,613
4708-Charges-WMS	$1,694,433
4714-Charges-NW	$1,235,637
4716-Charges-CN	$702,316
4750-Low Voltage	$205,513
TOTAL	**19,666,513**

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of OHL's operating revenue for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, the 2009 Bridge Year and the 2010 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue does not include revenue from commodity sales.

A summary of operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

Throughput Revenue:

Information related to OHL's throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year and CDM adjustments and known economic conditions. Detailed variance analysis on the throughput revenue is set out in Exhibit 3, Tab 3, Schedules 1 and 2.

Other Revenue:

Other revenues include Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues, to name a few. A summary of these operating revenues together with a materiality analysis of variances is presented in Exhibit 3, Tab 3, Schedules 1 and 2.

Revenue Sharing:

As noted in Exhibit 3, Tab 4, Schedule 1, OHL does not have a revenue sharing practice in place.

SUMMARY OF OPERATING REVENUE TABLE

Summary of Operating Revenue Table	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Actual	Variance from 2007 Actual	2009 Bridge	Variance from 2008 Actual	2010 Test	Variance from 2009 Bridge
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Distribution Revenue											
Residential	2,800,728	2,869,119	68,391	2,895,111	25,992	2,916,703	21,592	2,908,849	(7,855)	3,239,709	330,860
GS < 50 kW	612,504	664,239	51,735	698,274	34,035	717,968	19,693	724,478	6,511	834,494	110,015
GS > 50 kW	793,088	670,673	(122,415)	678,571	7,897	679,711	1,141	684,837	5,125	861,026	176,189
Streetlight	5,210	5,385	174	5,129	(256)	5,469	339	5,403	(65)	49,159	43,755
Sentinel Light	1,415	1,370	(44)	1,372	2	1,337	(35)	1,364	27	6,558	5,194
Unmetered Scattered Load	-	13,334	13,334	16,075	2,741	16,448	373	14,591	(1,857)	15,018	427
Total	4,212,945	4,224,121	11,175	4,294,532	70,412	4,337,636	43,104	4,339,522	1,886	5,005,962	666,441
Other Distribution Revenue											
Late Payment Charges	38,561	51,243	12,682	40,838	(10,405)	31,368	(9,471)	36,967	5,599	37,522	555
Specific Service Charges	118,115	97,028	(21,086)	156,217	59,189	154,769	(1,448)	161,365	6,596	159,163	(2,202)
Other Distribution Revenue	59,682	76,776	17,094	103,053	26,277	98,945	(4,108)	100,297	1,352	100,592	295
Other Income and Expenses	110,685	337,953	227,267	330,802	(7,151)	227,734	(103,068)	169,462	(58,272)	160,862	(8,600)
Total	327,043	563,001	235,958	630,910	67,909	512,816	(118,095)	468,091	(44,724)	458,139	(9,952)
Grand Total:	4,539,989	4,787,122	247,133	4,925,443	138,321	4,850,452	(74,991)	4,807,613	(42,839)	5,464,101	656,488

VARIANCE ANALYSIS ON OPERATING REVENUE:

OHL's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2008-0177 and EB-2008-0204 dated March 19, 2009. OHL's distribution revenue for 2010 has been calculated to included the revenue deficiency according to Exhibit 6, Schedule 1, Tab 1. As noted above, distribution revenue does not include commodity-related revenue.

A summary of normalized operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

2006 Board Approved:

OHL's 2006 Board Approved operating revenue was forecast to be $ 4,539,989 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $ 4,212,945 or of total revenues. Other operating revenue (net) accounts for the remaining revenue of $ 327,043 . This amount does not include the revenues and expenses in accounts 4375 and 4380 as per the 2006 EDR Rate handbook.

2006 Actual:

OHL's operating revenue in fiscal 2006 was $ 4,787,122 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $ 4,224,121 or 88.2% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $ 563,001 . This amount includes the revenues and expenses in accounts 4375 and 4380.

Comparison to 2006 Board Approved:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $ 247,133 higher than the 2006 Board Approved level forecasted. The distribution revenue increase of $ 11,175 resulted from higher than forecasted consumption levels, mainly in the residential rate class. The other distribution revenue increase of $ 235,958 was due to improved pricing on scrap material (copper), the billing of water and sewer and the streetlight maintenance (accounts 4375 and 4380) that were not included in the 2006 EDR. There was also revenue generated for management services provided by OHL from July 1, 2006 to December 31, 2006 to Grand Valley Energy Inc.(GVEI). GVEI had a billing system and were the only deregulated client of the software vendor. GVEI did not have the ability to settle with the retailers and they also had their sole management staff depart from the company. The revenues generated from the non-utility revenue accounted for $ 102,570 of the above amount.

2007 Actual:

OHL's operating revenue in fiscal 2007 was $ 4,925,443 , as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $ 4,294,532 or 87.2% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $ 630,910 . This includes the revenues and expenses in accounts 4375 and 4380.

Comparison to 2006 Actual*:*

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $ 138,321 higher than the 2006 actual operating revenue. This increase of $ 70,412 resulted from increased distribution rates and an increase in consumption levels. The increase in other revenue of $ 67,909 was due to the partial year realization of increased Specific Service Charge rates approved in the 2006 EDR. The billing of water and sewer and the streetlight maintenance (accounts 4375 and 4380) generated revenues that were not included in the 2006 EDR. There was also revenue generated for management services provided by OHL from January 1, 2007 to December 31, 2007 to Grand Valley Energy Inc.(GVEI). The non-utility revenues amounted to $ 132,961 .

2008 Actual:

OHL's operating revenue in fiscal 2008 is $ 4,850,452 , as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $ 4,337,636 or 89.4% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $ 512,816 . This includes the revenues and expenses in accounts 4375 and 4380.

Comparison to 2007 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $ (74,991) lower than the 2007 actual operating revenue. This decrease is the result of the other operating revenue amounting to $ (118,095) and was largely due to the decrease in interest rates for interest earned in our bank account.

2009 Bridge:

OHL's operating revenue is forecast to be $ 4,807,613 , as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $ 4,339,522 or 90.3% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $ 468,091 . This includes the revenues and expenses in accounts 4375 and 4380.

Comparison to 2008 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $ (42,839) lower than the actual year level in fiscal 2008. Part of the decrease related to a decrease in distribution revenue that amounted to $ 1,886 resulting in a decrease residential consumption due to OPA CDM programs. This decrease is the result of forecasted reduced revenues from other distribution revenue most significantly, lower interest income due to decreased rate of interest in this period.

2010 Test Year:

OHL's operating revenue is forecast to be $ 5,464,101 in fiscal 2010, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $ 5,005,962 or 91.6% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $ 458,139 . This includes the revenues and expenses in accounts 4375 and 4380.

Comparison to 2009 Bridge Year:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $ 656,488 above the bridge year level in fiscal 2009. This increase is the result of an increase in revenue requirement for 2010. See Exhibit 6, Tab 1, Schedule 1 for an explanation of the revenue deficiency for 2010 test year.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by OHL to prepare the weather normalized load and customer/connection forecast used to design the proposed distribution rates. In summary, OHL reviewed the various processes used by the 2009 cost of service applicants and is proposing to adopt a weather normalization forecasting method similar to the one used by Toronto Hydro Electric System Ltd in its 2008, 2009 and 2010 rate application (EB-2007-0680). A similar method was also approved by the Board for the following 2009 cost of service applicants.

a) Innisfil Hydro Distribution Systems Ltd.

b) Lakeland Power Distribution Ltd.

c) Niagara-on-the-Lake Hydro Inc.

d) Thunder Bay Hydro Electricity Distribution Inc.

In summary, Orangeville Hydro has used the same regression analysis methodology used by the distributors mentioned above to determine a prediction model. With regards to the overall process of load forecasting, it is Orangeville Hydro’s view that the conducting a regression analysis on historical purchases to produce an equation that will predict purchases is appropriate. Orangeville Hydro knows by month the exact amount of kWhs purchased from the IESO and others for use by customers of Orangeville Hydro. With a regression analysis these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of regression analysis produces a equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for Orangeville Hydro for the bridge and test year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later on in this evidence.

During the review process of the 2009 cost of service applications, Intervenors expressed concerns with the load forecasting weather process being proposed by Orangeville Hydro. Intervenors suggested the weather normalization should be conducted on an individual rate class basis and the regression analysis would be based on monthly billed kWh by rate class. In Orangeville Hydro's view, conducting a regression analysis which relates the monthly billed kWh of a class is to other monthly variables is problematic. The monthly billed amount is not the amount consumed in the month but the amount billed. The amount billed is based on billing cycle meter reading schedules whose reading dates vary and typically are not at month end. The amount billed could include consumption from the month before or even further back. By using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be reasonable, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In Orangeville Hydro's view, variables such as heating degree days impact the amount consumed not the amount billed. It is possible to estimate the amount consumed in a month based on the amount billed but until smart meters are fully deployed this would only be an estimate which in Orangeville Hydro's view would reduce the accuracy of a regression model that is based on monthly billing data. In addition, Orangeville Hydro does not have as many years of monthly historical billed data by rate class as it does for the amount purchased. As a result, conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

Orangeville Hydro understands that to a certain degree the process of developing a load forecast for cost of service rate application is an evolving science for electric distributors in the province. Orangeville Hydro expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by taking into consideration data provided by smart meters and how others are conducting load forecasts in future cost of service rate applications. However, based on the Board's approval of this methodology in a number of 2009 applications as well as the discussion that follows, Orangeville Hydro submits the load forecasting methodology is reasonable at this time for the purposes of this application.

OHL also tested our load forecast model using the 20-year weather HDD/CDD values and found that the prediction using the 20-year was greater by 1,297,166 kWhs. The 20-year weather HDD/CDD forecast predicted a total consumption in 2010 of 262,018,901 whereas the 10-year weather HDD/CDD predicted a total consumption of 263,316,067. OHL will utilize the data based on the 10-year HDD/CDD since it reflects more recent weather conditions and produces a higher forecast than the 20-year trended numbers. Table 1 below provides a summary of the weather normalized load and customer/connection forecast used in this application.

Table 1
Summary of Load and
Customer/Connection Forecast

Year	Billed (kWh)	Growth (kwh)	Percentage Change %	Customer/ Connection Count	Growth	Percentage Change %
2001				11,707		
2002	234,925,579			12,233	526	4.49%
2003	240,614,498	5,688,919	2.42%	12,908	675	5.51%
2004	242,286,509	1,672,011	0.69%	13,196	288	2.23%
2005	249,806,945	7,520,436	3.10%	13,331	136	1.03%
2006	250,897,683	1,090,737	0.44%	13,438	107	0.80%
2007	256,622,372	5,724,689	2.28%	13,558	121	0.90%
2008	249,716,485	-6,905,886	-2.69%	13,784	226	1.67%
2009	252,054,931	2,338,445	0.94%	14,028	244	1.77%
2010	249,029,139	-3,025,792	-1.20%	14,303	275	1.96%

2000 to 2008 are weather actual and 2009 and 2010 are weather normalized. OHL currently does not have a process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this application.

The streetlight, sentinel lights and unmetered scattered loads are measured as connections. On a rate class basis, actual and forecasted billed amount and number of customers are shown in Table 2 and customer usage is shown in Table 3.

Table 2

Billed Energy and Number of Customers by Rate Class

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Energy (kWh)							
2002	83,551,303	29,613,141	120,074,463	1,553,494	133,178	0	234,925,579
2003	82,401,296	30,457,263	126,068,508	1,553,494	133,937	0	240,614,498
2004	82,624,722	30,592,102	127,240,150	1,695,517	134,018	0	242,286,509
2005	87,597,049	34,393,460	126,094,033	1,587,030	135,374	0	249,806,945
2006	85,059,823	35,198,596	128,541,421	1,594,469	130,122	373,252	250,897,683
2007	85,922,369	37,055,213	131,518,571	1,615,441	133,476	377,302	256,622,372
2008	85,459,087	37,433,972	124,560,248	1,734,012	136,892	392,274	249,716,485
2009	85,073,410	38,776,135	125,942,329	1,766,075	129,305	367,676	252,054,931
2010	84,928,233	38,954,924	122,840,423	1,798,732	129,899	376,928	249,029,139
Number of Customers/Connections							
2002	8,602	918	137	2,413	164	0	12,233
2003	9,073	972	143	2,557	164	0	12,908
2004	9,278	983	146	2,622	168	0	13,196
2005	9,425	986	138	2,573	173	0	13,294
2006	9,483	994	130	2,506	175	151	13,438
2007	9,547	1,030	131	2,519	179	154	13,558
2008	9,619	1,061	132	2,643	177	154	13,784
2009	9,813	1,081	133	2,683	168	151	14,028
2010	10,045	1,081	133	2,724	170	151	14,303

Table 3

Annual Usage per Customer/Connection by Rate Class

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Energy Usage per Customer/Connection (kWh per Customer/Connection)						
2002	9,713	32,276	876,456	644	812	0
2003	9,083	31,351	881,598	608	817	0
2004	8,905	31,137	874,503	647	798	0
2005	9,294	34,900	913,725	617	783	0
2006	8,970	35,429	992,598	636	744	2,472
2007	9,000	35,993	1,007,805	641	748	2,450
2008	8,885	35,298	943,638	656	776	2,547
2009	8,670	35,887	946,935	658	770	2,435
2010	8,455	36,053	923,612	660	764	2,496
Annual Growth Rate in Usage per Customer/Connection						
2002						
2003	-6.9%	-3.0%	0.6%	-6.0%	0.6%	0.0%
2004	-2.0%	-0.7%	-0.8%	6.0%	-2.4%	0.0%
2005	4.2%	10.8%	4.3%	-4.8%	-1.9%	0.0%
2006	-3.6%	1.5%	7.9%	3.0%	-5.2%	100.0%
2007	0.3%	1.6%	1.5%	0.8%	0.6%	-0.9%
2008	-1.3%	-2.0%	-6.8%	2.3%	3.6%	3.8%
2009	-2.5%	1.6%	0.3%	0.3%	-0.8%	-4.6%
2010	-2.5%	0.5%	-2.5%	0.3%	-0.8%	2.5%

LOAD FORECAST AND METHODOLOGY

OHL's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, and economic data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class is determined using time-series econometric methodologies. The forecast is also adjusted for CDM and loss of load from industrial customers who have recently reduced their operations. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth), population and calendar variables (days in month, seasonal). The regression model uses monthly kWh and monthly values of independent variables from January 1998 to December 2008 to determine the monthly regression coefficients.

Data for OHL's total system load is available as far back as January 1998. This provides over 140 monthly data points, which is a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard it is OHL's view that it is appropriate to review the impact of weather since 1998 on the energy usage and then determine the average weather conditions from 1998 to 2008 which would be applied in the forecasting process to determine a weather normalized forecast.

The multifactor regression model has determined primary drivers of year-over-year changes in OHL's load growth are economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Economic growth – which encompasses population trends in the OHL’s service area as well as general economic conditions, are captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP") and population statistics.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The third main factor determining energy use in the monthly model can be classified as "calendar factors". For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month and a “flag” variable to capture the typically lower usage in the spring and fall months.

The model predicted kWh purchased by OHL is as follows:

OHL Monthly Predicted kWh Purchases
= Heating Degree Days x 5,143.06
+ Cooling Degree Days x 29,426.86
+ Ontario Real GDP Monthly Index x 41,477.12
+ Population x 550
+ Number of Days in the Month x 436,323.71
+ Spring Fall Flag x (721,249.27)
+ Constant of (16,592,864.55).

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

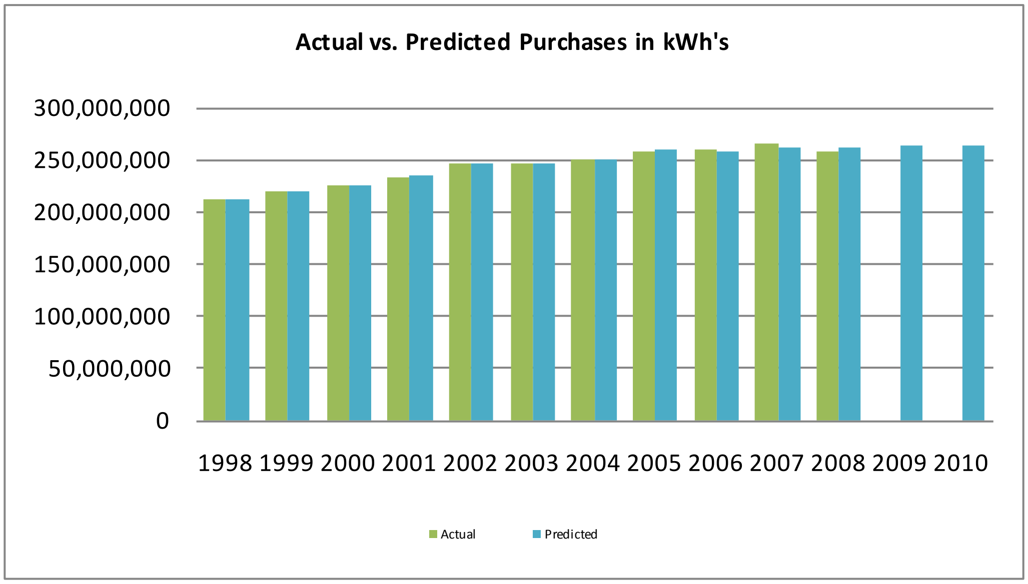
The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Data for the Orangeville MOE weather station was used;
b) For 1988 to 2007, the 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance. For 2008 to 2010, the 2009 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance ;
c) Population data was based on Census population data for the Town of Orangeville; and
d) The calendar provided information related to number of days in the month and the spring/fall flag.

The chart below shows the statistics that were used for the load forecast, using regression analysis.

Statistic	**Value**
R Square	88%
Adjusted R Square	88%
F Test	116.2
T-stats by Coefficient	
Intercept	(5.2)
Heating Degree Days	13.7
Cooling Degree Days	6.6
Ontario Real GDP Monthly %	1.6
Number of Days in Month	5.5
Spring Fall Flag	(4.4)
Population	2.9
Number of Peak Hours	1.3
Blackout Flag	(1.2)

The annual results of the above prediction formula compared to the actual annual purchases from 1998 to 2007 are shown in the chart below. The prediction formula has a statistical R^2 of 88% which generally indicates the formula has a very good fit to the actual data set.



The following table outlines the data that supports the above chart. In addition, the weather normalized forecast of total system purchases for OHL is provided for 2009 and 2010.

Table 4

OHL's Total System Purchases

	Purchased without Losses	Predicted Purchases	% Difference
1998	211,937,576	211,540,125	-0.19%
1999	220,012,006	220,660,197	0.29%
2000	225,170,572	225,756,450	0.26%
2001	233,902,971	234,312,495	0.17%
2002	245,981,742	245,676,270	-0.12%
2003	247,360,826	246,213,921	-0.47%
2004	249,629,277	250,041,115	0.16%
2005	258,210,340	258,943,463	0.28%
2006	259,662,833	258,167,939	-0.58%
2007	265,059,732	262,611,965	-0.93%
2008	257,950,545	260,954,481	1.15%
2009		262,826,600	
2010		263,316,067	

The forecasted weather normalized amount for 2009 and 2010 is determined by using a forecast of the dependent variables in the prediction formula on a monthly basis. In order to incorporate weather normal conditions, the average monthly heating degree days and cooling degree days which have occurred from 1998 to 2007 is applied in the prediction formula. The details on the average monthly heating degree days and cooling degree days are shown in Appendix A.

Since the prediction formula is based on ten years of historical monthly data it is not able to predict the impact on the forecast for recent events that have caused changes in energy sales. These events include industrial customers that have recently shut-down or reduced operations and CDM programs that have been in place for a relatively short time (i.e. less than an year and a half). As a result, "manual" adjustments have been made to the forecast to reflect these changes. Table 5 shows the predicted purchases before and after the adjustments for those years in which adjustments were made.

Table 5

Predicted Purchases Before and After Adjustments

	Predicted Before Adjustments (kWh)	Adjustments (kWh)	Predicted After Adjustments (kWh)
2009	262,826,600	(2,065,036)	260,761,564
2010	263,316,067	(5,564,080)	257,751,986

The following table outlines the sources of the manual adjustments made to the forecast.

Table 6

Manual Adjustment to Forecast

	PolyOne Canada Inc.	Johnson Controls Ltd.	Pfizer Canada	The Data Group of Canada	CDM	Total
2009	(1,352,780)	0	(88,451)	338,195	(962,000)	(2,065,036)
2010	(1,352,780)	(3,140,380)	(439,653)	338,784	(962,000)	(5,556,029)

Polyone Canada Inc's annual energy sales including losses was reduced by 866,000 kWh in 2008. Based on actual 2009 information from January to April it is expected the energy consumption will be reduced further by 1,352,780 in 2009 which is also the assumed reduction in energy for the 2010 forecast with the forecasted loss factor. There has been a significant reduction in energy usage due to the economic downturn resulting in less orders and therefore shift/staff reductions.

Johnson Controls' annual energy consumption in 2008 has reduced by 669,000 kWh from 2007, including losses. Johnson Controls manufactures parts for the automobile industry. The controller of Johnson Controls informed OHL that they expected the energy consumption will be the same in 2009 however the plant is scheduled to close mid-2010 therefore the consumption has been reduced by 3,140,380 kWh reflecting this loss.

Pfizer Canada's annual energy consumption in 2008 has reduced by 487,000 kWh from 2007, including losses. This plant that manufactures pharmaceuticals is not operating at full scale and has turned off the power to part of the building where it is empty. They will be closing their doors in 2010. It is expected the energy consumption will be reduced a further 88,451 kWh in 2009. In 2010 due to the imminent closure results in a further reduction of 439,653 kWh which is the assumed reduction in energy for the 2010 forecast.

OHL found there was a billing error in 2008 due to an incorrect billing multiplier. To adjust this error for The Data Group, consumption has been added to the forecast for both 2009 and 2010.

OHL has participated in a number of Ontario Power Authority developed CDM programs within its service area and the results have been very positive as can been seen in the decline in usage. It is OHL's view that CDM programs that were offered prior to 2008 have impacted the historical usage per customer. However, OHL has determined through the OPA Conservation Programs report and based on the same number of customers participating there should be a further reduction in usage for 2009 and 2010. Consequently, a manual adjustment to the forecast has been made to reflect the savings in energy for 2009 and 2010 resulting from the CDM programs. This adjustment including losses is 962,000 (kWh) for 2009 and 2010. It is assumed energy savings that have occurred in 2007 and 2008 will continue in 2009 and 2010.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. As outlined in Table 7 below, historically the OHL loss factor on average has been 3.43%

Table 7

Historical Loss Factor

	Actual Purchases (kWh)	Actual Billed (kWh)	Loss Factor
2002	245,981,742	234,925,579	4.71%
2003	247,360,826	240,614,498	2.80%
2004	249,629,277	242,286,509	3.03%
2005	258,210,340	249,806,945	3.36%
2006	259,662,833	250,897,683	3.49%
2007	265,059,732	256,622,372	3.29%
2008	257,950,545	249,716,485	3.30%
		Average	3.43%

With this average loss factor the total weather normalized billed energy will be 252,054,931 kWh for 2009 (i.e. 260,700,415/1.0343) and 249,029,139 for 2010 (i.e. 257,570,838/1.0343)

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 8 below.

Table 8

Historical Customer/Connection Data

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2002	8,602	918	137	2,413	164	0	12,233
2003	9,073	972	143	2,557	164	0	12,908
2004	9,278	983	146	2,622	168	0	13,196
2005	9,425	986	138	2,573	173	0	13,294
2006	9,483	994	130	2,506	175	151	13,438
2007	9,547	1,030	131	2,519	179	154	13,558
2008	9,619	1,061	132	2,643	177	154	13,784

From the historical customer/connection data, the growth rate in customer/connection can be evaluated and is provided in Table 9 below. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average growth rate on a compounding basis.

Table 9

Growth Rate in Customer/Connections

Growth Rate in Customer/Connection						
Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Number of Customers/Connections						
2003	5.2%	5.6%	4.2%	5.6%	0.0%	
2004	2.2%	1.1%	1.7%	2.5%	2.4%	
2005	1.6%	0.3%	-5.4%	-1.9%	2.9%	
2006	0.6%	0.8%	-6.6%	-2.7%	1.1%	100.0%
2007	0.7%	3.5%	0.8%	0.5%	2.0%	1.9%
2008	0.7%	2.9%	1.1%	4.7%	-1.1%	0.0%
2009	2.0%	1.9%	0.8%	1.5%	-5.1%	-2.0%
2010	2.3%	0.0%	0.0%	1.5%	1.2%	0.0%

The resulting geometric mean is applied to the 2008 customer/connection numbers to determine the forecast of customer/connections for 2009 and 2010. Table 10 outlines the forecast of customers by rate class for 2009 and 2010.

Table 10

Customer/Connection Forecast

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2009	9,813	1,081	133	2,683	168	151	14,028
2010	10,045	1,081	133	2,724	170	151	14,303

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following Table 11 provides the average annual usage per customer by rate class from 2000 to 2008 where data is available.

Table 11

Historical Annual Usage per Customer

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Annual kWh Usage per Customer/Connection						
2002	9,713	32,276	876,456	644	812	0
2003	9,083	31,351	881,598	608	817	0
2004	8,905	31,137	874,503	647	798	0
2005	9,294	34,900	913,725	617	783	0
2006	8,970	35,429	992,598	636	744	2,472
2007	9,000	35,993	1,007,805	641	748	2,450
2008	8,885	35,298	943,638	656	776	2,547

Usage per customer/connection can only be determined for 2002 and onward since historical billed energy by rate class is only available from 2002. As can been seen from the above table usage per customer/connection essentially declines for the residential class after 2005. As stated previously, it is OHL’s view that this decline is partially due to the CDM programs.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided on the following Table 12. The geometric mean growth rate has also been shown.

Table 12

Growth Rate in Usage Per Customer/Connection

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Growth Rate in Usage per Customer/Connection						
2002						
2003	-6.9%	-3.0%	0.6%	-6.0%	0.6%	0.0%
2004	-2.0%	-0.7%	-0.8%	6.0%	-2.4%	0.0%
2005	4.2%	10.8%	4.3%	-4.8%	-1.9%	0.0%
2006	-3.6%	1.5%	7.9%	3.0%	-5.2%	100.0%
2007	0.3%	1.6%	1.5%	0.8%	0.6%	-0.9%
2008	-1.3%	-2.0%	-6.8%	2.3%	3.6%	3.8%
Geomean	0.9853	1.0150	0.9867	1.0031	0.9924	1.0252

For the forecast of usage per customer/connection the historical geometric mean was used for all rate classes.

Table 13

Forecast Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Forecast Annual kWh Usage per Customer/Connection						
2009	8,670	35,887	946,935	658	770	2,435
2010	8,455	36,053	923,612	660	764	2,496

With the preceding information the non-normalized weather billed energy forecast can be determine by applying the forecast number of customer/connection from Table 10 by the forecast of annual usage per customer/connection from Table 13. The resulting non-normalized weather billed energy forecast is shown in Table 14 below.

Table 14

Non-Normalized Weather Billed Energy Forecast

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2009	84,935,414	38,713,237	125,760,479	1,766,075	129,305	367,676	251,672,186
2010	85,669,984	39,295,151	123,794,361	1,798,732	129,899	376,928	251,065,055

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 252,054,931 kWh for 2009 and 249,029,139 kWh for 2010 These forecast numbers reflect manual adjustment previously discussed but prior to the manual adjustments the total weather normalized billed energy forecast would have been 254,119,967 kWh in 2009 (i.e. 262,826,600 kWh) from Table 5 divided by the loss factor of 1.0343 from Table 7) and 254,593,219 kWh in 2010 (i.e. 263,316,067 kWh) from Table 5 divided by the loss factor of 1.0343 from Table 7).

The difference between the non-normalized and normalized forecast before manual adjustments is 382,744 kWh in 2009 (i.e. 251,672,186 – 252,054,931) and -2,035,916 kWh in 2010 (i.e. 251,065,055 – 249,029,139). This difference will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for OHL for the cost allocation study, which has been used to support this rate application, it was determined the weather sensitivity by rate classes is as follows.

Table 15
Weather Sensitivity by Rate Class

Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Weather Sensitivity					
100%	100%	89%	0%	0%	0%

As a result, the difference between the non-normalized and normalized forecast has been assigned on a prorated basis to each rate class based on the above level of weather sensitivity. The following tables outline how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast. In addition, the impact of the manual adjustments by rate class is also included to show how the weather normalized billed energy forecast after adjustments have been determined. The manual adjustments are at the billed level which excludes losses.

Table 16

Alignment of Non-Normal to Weather Normal Forecast

Year	Residential	General Service < 50kW	General Service > 50kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-normalized Weather Billed Energy Forecast (kWh)							
2009	85,897,414	38,713,237	126,863,515	1,766,075	129,305	367,676	253,737,222
2010	86,631,984	39,295,151	128,396,441	1,798,732	129,899	376,928	256,629,135
Adjustment for Weather (kWh)							
2009	137,996	62,898	181,850	0	0	0	382,744
2010	-741,751	-340,227	-953,938	0	0	0	-2,035,916
Manual Adjustment to Billed Energy Forecast for Loss of Load							
2009	-962,000	0	-1,103,036	0	0	0	-2,065,036
2010	-962,000	0	-4,602,080	0	0	0	-5,564,080
Weather Normalized Billed Energy Forecast (kWh)							
2009	85,073,410	38,776,135	125,942,329	1,766,075	129,305	367,676	252,054,931
2010	84,928,233	38,954,924	122,840,423	1,798,732	129,899	376,928	249,029,139

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on a per kW basis. These include General Service > 50 to 999 kW, Streetlights and Sentinel Lights. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class for the years that data is available (i.e. 2002 to 2008).

Table 17

Historical Annual kW per Applicable Rate Class

Year	General Service > 50kW	Streetlights	Sentinel Lights
2002	283,998	4,654	363
2003	303,516	4,595	374
2004	301,178	4,701	372
2005	297,873	4,431	364
2006	304,914	4,452	370
2007	313,687	4,445	373
2008	297,642	4,842	379

The following is the historical ratio of kW/kWh as well as the average ratio from 2002 to 2008.

Table 18

Historical kW/KWh Ratio per Applicable Rate Class

Year	General Service > 50kW	Streetlights	Sentinel Lights
2002	0.2365%	0.2996%	0.2726%
2003	0.2408%	0.2958%	0.2792%
2004	0.2367%	0.2773%	0.2776%
2005	0.2362%	0.2792%	0.2685%
2006	0.2372%	0.2792%	0.2845%
2007	0.2385%	0.2752%	0.2797%
2008	0.2390%	0.2792%	0.2766%
Average	0.2378%	0.2836%	0.2770%

The average ratio was applied to the weather normalized billed energy forecast in Table 16 to provide the forecast of kW by rate class as shown below.

The following outlines the forecast of kW for the applicable rate classes.

Table 19

kW Forecast by Applicable Rate Class

Year	General Service > 50kW	Streetlights	Sentinel Lights
2009	300,571	5,009	358
2010	293,178	5,102	360

Summary of Forecast Data

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Weather Normal	2010 Weather Normal
Actual kWh Purchases		259,662,833	265,059,732	257,950,545		
Predicted kWh Purchases		258,167,939	262,611,965	260,954,481	262,826,600	263,316,067
Manual Adjustments					-1,103,036	-4,602,080
					261,723,564	258,713,986
% Difference		-0.6%	-0.9%	1.2%		
Billed kWh		250,897,683	256,622,372	249,716,485	252,054,931	249,029,139
By Class						
Residential						
Customers	9,392	9,483	9,547	9,619	9,813	10,045
kWh	83,847,548	85,059,823	85,922,369	85,459,087	85,073,410	84,928,233
General Service < 50 kW						
Customers	986	994	1,030	1,061	1,081	1,081
kWh	30,141,516	35,198,596	37,055,213	37,433,972	38,776,135	38,954,924
General Service > 50						
Customers	146	130	131	132	133	133
kWh	123,592,470	128,541,421	131,518,571	124,560,248	125,942,329	122,840,423
kW	299,583	304,914	313,687	297,642	300,571	293,178
Streetlights						
Connections	2,639	2,506	2,519	2,643	2,683	2,724
kWh	1,687,678	1,594,469	1,615,441	1,734,012	1,766,075	1,798,732
kW	4,838	4,452	4,445	4,842	5,009	5,102
Sentinel Lights						
Connections	172	175	179	177	168	170
kWh	140,307	130,122	133,476	136,892	129,305	129,899
kW	382	370	373	379	358	360
Unmetered Loads						
Customers	0	35	35	35	0	0
Connections	0	0	0	0	151	151
kWh	0	373,252	377,302	392,274	367,676	376,928
Total						
Customer/Connections	13,335	13,322	13,439	13,665	14,028	14,303
kWh	239,409,519	250,897,683	256,622,372	249,716,485	252,054,931	249,029,139
kW from applicable classes	304,802	309,736	318,505	302,862	305,938	298,639

Orangeville Hydro Limited
EB-2009-0272
Exhibit 3
Tab 2
Schedule 1
Appendix A
Filed: August 28, 2009

APPENDIX A

MONTHLY DATA USED FOR REGRESSION ANALYSIS

Appendix A

	Purchased without Losses	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Population	Predicted Purchases
Jan-98	19,765,630	696.8	0.0	100.4	31	0	23,701	19,414,831
Feb-98	17,349,033	569.7	0.0	100.8	28	0	23,769	17,424,989
Mar-98	18,569,053	572.1	0.0	101.2	31	1	23,837	18,237,517
Apr-98	16,343,087	342.8	0.0	101.6	30	1	23,906	16,598,510
May-98	16,428,457	90.5	18.1	102.0	31	1	23,974	16,243,348
Jun-98	17,266,036	80.0	48.9	102.4	30	0	24,042	17,593,869
Jul-98	17,438,503	23.4	53.9	102.8	31	0	24,110	17,939,705
Aug-98	17,967,225	17.7	53.2	103.2	31	0	24,178	17,785,981
Sep-98	16,537,523	91.1	11.4	103.6	30	1	24,246	15,910,996
Oct-98	16,905,561	294.3	0.0	104.0	31	1	24,315	17,111,665
Nov-98	18,187,393	431.1	0.0	104.4	30	1	24,383	17,433,246
Dec-98	19,180,075	664.4	0.0	104.8	31	0	24,451	19,845,467
Jan-99	21,110,745	776.7	0.0	105.4	31	0	24,484	20,386,922
Feb-99	18,283,804	696.8	0.0	106.1	28	0	24,517	18,711,489
Mar-99	19,460,632	610.5	0.0	106.7	31	1	24,550	19,139,693
Apr-99	16,936,415	377.9	0.9	107.4	30	1	24,583	17,421,300
May-99	16,914,440	213.1	6.9	108.0	31	1	24,616	17,150,797
Jun-99	18,375,911	56.4	41.0	108.7	30	0	24,650	17,836,436
Jul-99	18,711,508	3.9	83.2	109.3	31	0	24,683	19,213,311
Aug-99	17,610,535	43.6	29.0	110.0	31	0	24,716	17,868,416
Sep-99	16,629,000	102.6	24.8	110.7	30	1	24,749	16,936,481
Oct-99	17,392,919	314.5	0.0	111.3	31	1	24,782	17,698,338
Nov-99	18,484,201	420.1	0.0	112.0	30	1	24,815	18,010,499
Dec-99	20,101,897	643.7	0.0	112.7	31	0	24,848	20,286,515
Jan-00	21,235,608	777.4	0.0	113.2	31	0	24,874	20,929,192
Feb-00	19,675,466	642.2	0.0	113.7	29	0	24,900	19,477,618
Mar-00	19,444,592	490.6	0.0	114.2	31	1	24,926	19,044,281
Apr-00	17,834,902	398.1	0.0	114.8	30	1	24,952	17,849,888
May-00	17,995,777	178.8	18.0	115.3	31	1	24,978	17,962,088
Jun-00	18,312,438	59.7	30.9	115.8	30	0	25,005	18,051,393
Jul-00	18,390,648	38.8	26.3	116.4	31	0	25,031	18,122,435
Aug-00	19,289,431	43.3	36.3	116.9	31	0	25,057	18,634,713
Sep-00	18,381,054	130.0	21.6	117.4	30	1	25,083	17,367,888
Oct-00	18,883,435	253.3	0.0	118.0	31	1	25,109	17,921,738
Nov-00	13,618,622	496.5	0.0	118.5	30	1	25,135	18,851,283
Dec-00	22,108,600	833.7	0.0	119.1	31	0	25,161	21,543,932
Jan-01	22,008,402	738.8	0.0	119.2	31	0	25,302	21,375,849
Feb-01	19,874,695	667.7	0.0	119.4	28	0	25,442	19,627,359
Mar-01	20,965,894	645.2	0.0	119.6	31	1	25,583	20,342,363
Apr-01	17,928,918	348.3	0.0	119.8	30	1	25,723	18,304,289
May-01	18,240,103	161.5	6.8	119.9	31	1	25,864	18,223,962
Jun-01	19,332,580	65.6	39.5	120.1	30	0	26,005	18,985,052
Jul-01	18,917,069	34.0	37.2	120.3	31	0	26,145	19,276,034
Aug-01	20,103,432	10.2	82.7	120.4	31	0	26,286	20,654,437
Sep-01	17,813,256	126.7	16.3	120.6	30	1	26,426	17,989,047
Oct-01	19,056,000	295.2	0.0	120.8	31	1	26,567	19,134,661
Nov-01	19,201,115	371.1	0.0	121.0	30	1	26,707	19,174,192
Dec-01	20,461,507	574.3	0.0	121.1	31	0	26,848	21,225,250

Jan-02	20,465,312	644.3	0.0	121.5	31	0	26,867	21,846,159
Feb-02	21,580,255	606.7	0.0	121.9	28	0	26,886	20,210,898
Mar-02	19,555,518	604.8	0.0	122.2	31	1	26,905	20,814,636
Apr-02	20,518,923	367.9	7.3	122.6	30	1	26,924	19,559,345
May-02	19,098,721	281.7	4.5	122.9	31	1	26,943	19,494,751
Jun-02	19,592,206	64.4	42.9	123.3	30	0	26,963	19,658,399
Jul-02	21,553,873	11.6	116.6	123.7	31	0	26,982	22,177,026
Aug-02	20,842,050	20.3	66.8	124.0	31	0	27,001	20,704,837
Sep-02	19,711,953	53.5	36.9	124.4	30	1	27,020	18,781,855
Oct-02	19,872,161	357.8	6.3	124.8	31	1	27,039	20,067,984
Nov-02	20,934,578	517.4	0.0	125.1	30	1	27,058	20,215,526
Dec-02	22,256,193	678.1	0.0	125.5	31	0	27,077	22,144,853
Jan-03	23,798,653	871.4	0.0	125.7	31	0	27,107	23,319,819
Feb-03	21,216,124	779.6	0.0	125.8	28	0	27,137	21,402,936
Mar-03	21,474,156	629.3	0.0	126.0	31	1	27,167	21,321,468
Apr-03	19,652,029	425.3	1.0	126.1	30	1	27,197	19,887,802
May-03	18,969,925	225.1	0.0	126.2	31	1	27,227	19,287,955
Jun-03	19,424,221	65.4	28.0	126.4	30	0	27,258	19,597,916
Jul-03	20,636,868	14.2	51.0	126.5	31	0	27,288	20,547,895
Aug-03	19,975,390	14.9	65.7	126.7	31	0	27,318	19,975,390
Sep-03	18,931,126	107.9	5.1	126.8	30	1	27,348	18,489,415
Oct-03	20,311,207	341.1	0.0	127.0	31	1	27,378	20,075,207
Nov-03	20,808,045	444.3	0.0	127.1	30	1	27,408	20,032,982
Dec-03	22,163,082	634.8	0.0	127.3	31	0	27,438	22,275,134
Jan-04	24,137,766	904.0	0.0	127.5	31	0	27,479	23,693,021
Feb-04	21,496,194	696.9	0.0	127.8	29	0	27,520	21,708,899
Mar-04	21,956,341	567.3	0.0	128.1	31	1	27,560	21,465,100
Apr-04	19,745,368	386.9	0.0	128.3	30	1	27,601	19,975,992
May-04	19,313,552	207.2	6.6	128.6	31	1	27,642	19,635,098
Jun-04	19,371,000	88.6	22.4	128.9	30	0	27,683	19,967,499
Jul-04	20,329,491	25.7	41.1	129.1	31	0	27,723	20,586,035
Aug-04	20,119,319	66.0	23.8	129.4	31	0	27,764	20,317,749
Sep-04	19,670,302	72.3	9.2	129.7	30	1	27,805	18,796,264
Oct-04	19,954,288	297.6	0.0	129.9	31	1	27,846	20,073,480
Nov-04	20,383,768	452.1	0.0	130.2	30	1	27,886	20,624,372
Dec-04	23,151,886	736.0	0.0	130.5	31	0	27,927	23,197,604
Jan-05	24,197,063	837.6	0.0	130.7	31	0	27,968	23,673,607
Feb-05	20,802,799	676.6	0.0	131.0	28	0	28,008	21,570,790
Mar-05	22,087,997	674.5	0.0	131.3	31	1	28,049	22,340,582
Apr-05	19,486,247	377.0	0.0	131.6	30	1	28,089	20,331,187
May-05	19,289,246	269.3	0.0	131.9	31	1	28,130	20,248,347
Jun-05	22,058,553	23.0	95.0	132.2	30	0	28,170	22,174,702
Jul-05	22,253,301	9.5	98.5	132.5	31	0	28,211	22,520,138
Aug-05	22,144,541	13.0	62.5	132.8	31	0	28,251	21,671,540
Sep-05	20,085,753	68.1	17.3	133.1	30	1	28,292	19,424,382
Oct-05	20,656,476	274.0	5.0	133.4	31	1	28,332	20,511,662
Nov-05	21,550,876	445.4	0.0	133.7	30	1	28,373	21,003,405
Dec-05	23,597,490	724.7	0.0	134.0	31	0	28,413	23,473,121

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Exhibit 3
Tab 2
Schedule 1
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Jan-06	23,276,338	626.6	0.0	134.3	31	0	28,422	23,066,181
Feb-06	21,556,439	684.8	0.0	134.5	28	0	28,432	21,992,058
Mar-06	22,803,698	597.8	0.0	134.8	31	1	28,441	22,388,393
Apr-06	19,673,373	351.6	0.0	135.1	30	1	28,450	20,383,968
May-06	20,622,388	185.4	14.1	135.4	31	1	28,460	20,634,880
Jun-06	21,151,108	49.6	34.2	135.6	30	0	28,469	20,830,472
Jul-06	23,251,811	6.3	101.9	135.9	31	0	28,478	22,894,096
Aug-06	22,122,481	28.0	51.8	136.2	31	0	28,488	21,706,428
Sep-06	19,787,850	137.5	2.3	136.5	30	1	28,497	19,512,879
Oct-06	21,090,816	331.3	0.3	136.8	31	1	28,506	20,986,071
Nov-06	21,513,672	418.4	0.0	137.0	30	1	28,516	21,083,866
Dec-06	22,812,859	548.0	0.0	137.3	31	0	28,525	22,688,646
Jan-07	24,255,718	697.4	0.0	137.6	31	0	28,540	23,711,347
Feb-07	22,863,180	781.0	0.0	137.8	28	0	28,556	22,692,833
Mar-07	23,140,236	594.8	0.0	138.1	31	1	28,571	22,500,269
Apr-07	21,107,929	428.0	0.0	138.3	30	1	28,587	21,065,668
May-07	20,899,083	174.9	12.1	138.6	31	1	28,602	20,734,687
Jun-07	22,218,930	45.8	48.2	138.8	30	0	28,618	21,359,456
Jul-07	21,872,968	27.6	56.6	139.1	31	0	28,633	21,968,609
Aug-07	22,343,623	24.6	66.7	139.3	31	0	28,648	22,346,671
Sep-07	20,473,875	91.5	21.6	139.6	30	1	28,664	19,987,380
Oct-07	20,992,744	193.4	8.3	139.8	31	1	28,679	20,813,158
Nov-07	21,863,937	528.2	0.0	140.1	30	1	28,695	21,874,406
Dec-07	23,027,508	672.6	0.0	140.3	31	0	28,710	23,557,480
Jan-08	23,866,778	610.0	0.0	140.3	31	0	28,726	23,478,146
Feb-08	22,567,064	735.4	0.0	140.3	29	0	28,742	23,098,973
Mar-08	23,141,814	689.8	0.0	140.2	31	1	28,758	22,943,492
Apr-08	20,311,594	318.1	0.0	140.2	30	1	28,773	20,839,579
May-08	19,809,489	234.4	0.0	140.1	31	1	28,789	20,773,075
Jun-08	20,585,801	45.8	27.5	140.1	30	0	28,805	20,904,015
Jul-08	21,932,125	10.1	58.2	140.0	31	0	28,821	22,146,004
Aug-08	20,775,868	36.6	23.0	140.0	31	0	28,837	21,095,008
Sep-08	19,995,845	95.2	11.1	139.9	30	1	28,853	19,974,508
Oct-08	20,604,533	308.2	0.0	139.9	31	1	28,868	21,265,536
Nov-08	21,299,908	391.1	0.0	139.8	30	1	28,884	21,025,002
Dec-08	23,059,725	597.9	0.0	139.8	31	0	28,900	23,411,142
Jan-09	22,556,183	743.7	0.0	139.5	31	0	28,903	24,150,208
Feb-09	20,660,459	685.2	0.0	139.2	28	0	28,905	22,371,179
Mar-09	21,145,448	607.0	0.0	138.9	31	1	28,908	22,782,924
Apr-09	19,048,980	374.7	0.8	138.6	30	1	28,910	21,007,723
May-09	18,871,017	202.0	7.9	138.3	31	1	28,913	20,753,223
Jun-09	19,789,889	58.6	41.7	138.0	30	0	28,915	21,441,390
Jul-09	20,480,742	18.6	65.9	137.7	31	0	28,918	22,373,286
Aug-09	20,299,445	28.9	51.0	137.4	31	0	28,920	21,821,142
Sep-09	18,910,685	97.9	16.1	137.2	30	1	28,923	20,059,452
Oct-09	19,610,922	296.4	1.8	136.9	31	1	28,925	21,084,473
Nov-09	19,804,192	446.9	0.0	136.6	30	1	28,928	21,278,925
Dec-09	21,992,802	664.4	0.0	136.3	31	0	28,930	23,702,674
Jan-10	22,809,870	748.0	0.0	136.5	31	0	28,933	23,986,658
Feb-10	20,961,498	695.7	0.0	136.8	28	0	28,935	22,341,910
Mar-10	21,379,666	610.1	0.0	137.1	31	1	28,938	22,818,156
Apr-10	19,294,971	377.6	0.9	137.3	30	1	28,940	20,987,800
May-10	19,093,067	212.1	7.0	137.6	31	1	28,943	20,764,111
Jun-10	20,019,331	56.6	41.0	137.8	30	0	28,945	21,421,131
Jul-10	20,757,309	18.2	67.0	138.1	31	0	28,948	22,356,113
Aug-10	20,511,465	29.9	50.8	138.4	31	0	28,950	21,954,963
Sep-10	19,126,427	98.5	16.6	138.6	30	1	28,953	20,153,598
Oct-10	19,856,864	296.6	2.0	138.9	31	1	28,955	21,112,552
Nov-10	19,951,174	448.3	0.0	139.2	30	1	28,958	21,489,826
Dec-10	22,248,505	664.4	0.0	139.4	31	0	28,960	23,929,250

Table 1

SUMMARY OF OTHER OPERATING REVENUE

Uniform System of Account #	Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
4235	Specific Service Charges	118,115	97,028	156,217	154,769	161,365	159,163
4225	Late Payment Charges	38,561	51,243	40,838	31,368	36,967	37,522
4080	SSS Admin Fees	28,474	26,380	26,619	27,006	26,087	26,087
4082	Retail Services Revenues	15,809	21,206	18,311	17,132	19,257	19,546
4084	Service Transaction Requests (STR) Revenues	128	438	494	291	436	443
4205	Interdepartmental Rents	0	0	0	0	0	0
4210	Rent from Electric Property	8,381	28,753	57,629	54,516	54,516	54,516
4215	Other Utility Operating Income	6,000	0	0	0	0	0
4220	Other Electric Revenues	890	0	0	0	0	0
4240	Provision for Rate Refunds	0	0	0	0	0	0
4245	Government Assistance Directly Credited to Income	0	0	0	0	0	0
4305	Regulatory Debits	0	0	0	0	0	0
4310	Regulatory Credits	0	0	0	0	0	0
4315	Revenues from Electric Plant Leased to Others	0	0	0	0	0	0
4320	Expenses of Electric Plant Leased to Others	0	0	0	0	0	0
4325	Revenues from Merchandise, Jobbing, Etc.	0	0	0	0	0	0
4330	Costs and Expenses of Merchandising, Jobbing, Etc	0	0	0	0	0	0
4335	Profits and Losses from Financial Instrument Hedges	0	0	0	0	0	0
4340	Profits and Losses from Financial Instrument Investme	0	0	0	0	0	0
4345	Gains from Disposition of Future Use Utility Plant	0	0	0	0	0	0
4350	Losses from Disposition of Future Use Utility Plant	(2,342)	0	0	0	0	0
4355	Gain on Disposition of Utility and Other Property	10,275	18,443	11,313	694	15,120	1,600
4360	Loss on Disposition of Utility and Other Property	0	(10,529)	(376)	(4,341)	0	0
4365	Gains from Disposition of Allowances for Emission	0	0	0	0	0	0
4370	Losses from Disposition of Allowances for Emission	0	0	0	0	0	0
4375	Revenues from Non-Utility Operations	0	463,491	555,973	651,937	443,131	491,857
4380	Expenses of Non-Utility Operations	0	(360,921)	(423,012)	(529,285)	(350,930)	(377,906)
4385	Non-Utility Rental Income	0	1,965	2,071	1,401	0	0
4390	Miscellaneous Non-Operating Income	1,943	14,598	10,633	15,877	17,257	500
4395	Rate-Payer Benefit Including Interest	0	0	0	0	0	0
4398	Foreign Exchange Gains and Losses, Including Amortiz	0	0	0	0	0	0
4405	Interest and Dividend Income	100,809	210,906	174,200	91,451	44,885	44,810
4415	Equity in Earnings of Subsidiary Companies	0	0	0	0	0	0
	Total:	**327,043**	**563,001**	**630,910**	**512,816**	**468,091**	**458,139**
Specific Service Charges		118,115	97,028	156,217	154,769	161,365	159,163
Late Payment Charges		38,561	51,243	40,838	31,368	36,967	37,522
Other Distribution Revenues		59,682	76,776	103,053	98,945	100,297	100,592
Other Income and Expenses		110,685	337,953	330,802	227,734	169,462	160,862
	Total:	**327,043**	**563,001**	**630,910**	**512,816**	**468,091**	**458,139**
Less	**Revenue Non-Utililty Operations/Water**		**304,108**	**318,860**	**350,027**	**346,440**	**390,063**
Less	**Water/Sewer Penalties**		**0**	**9,155**	**17,660**	**20,000**	**20,300**
Less	**Expenses Non Utility Operation/Water**		**(219,491)**	**(222,787)**	**(268,297)**	**(285,686)**	**(311,683)**
Less	**Regulatory Asset Carrying Charges**		**30,228**	**11,148**	**8,532**	**2,387**	**2,387**
Less	**50% of Gain on Disposition**						**800**
	TOTAL REVENUE OFFSETS		**448,156**	**514,534**	**404,893**	**384,950**	**356,272**

VARIANCE ANALYSIS ON OTHER OPEATING REVENUE:

Preamble:

OHL's 2010 revenue requirement is $5,362,234 therefore the Materiality threshold used to analyze Other Operating Revenue in accordance with the Filing Requirements is $50,000 for distributors with a distribution revenue requirement less than or equal to $10 million. To allow for the most detailed review of materiality on Other Operating Revenue, OHL has selected the materiality of $25,000. OHL has provided explanations for the following variances, which exceed the materiality threshold. The following variances exceed the materiality threshold.

2006 Board Approved Comparison to 2006 Actual:

OHL's 2006 Board Approved other operating revenue was forecast to be $ 327,043 as shown in Exhibit 3, Tab 3, Schedule 1. This amount does not include the revenues and expenses in accounts 4375 and 4380 as per the 2006 EDR Rate handbook. OHL's other operating revenue in fiscal 2006 was $ 563,001 as shown in Exhibit 3, Tab 3, Schedule 1. The variance from the 2006 Board-Approved was $ 235,958 resulting from the difference in the interest rates and also includes the revenues and expenses in accounts 4375 and 4380. These differences are further explained in Table 1 and Table 2 below.

2007 Actual Comparison to 2006 Actual:

OHL's other operating revenue in fiscal 2007 was $ 630,910 , as shown in Exhibit 3, Tab 3, Schedule 1.

The other operating revenue variance of $ 67,909 from 2006 actual was a result of the partial year realization of increased Specific Service Charge rates approved in the 2006 EDR. There was also revenue generated for management services provided by OHL from January 1, 2007 to December 31, 2007 to Grand Valley Energy Inc.(GVEI) as noted in Table 2 below.

2008 Actual Comparison to 2007 Actual:

OHL's 2008 other operating revenue is $ 512,816 , as shown in Exhibit 3, Tab 3, Schedule 1. The variance from 2007 was a decrease of $ (118,095) due to the decrease in the interest rates and non-utility expenses relating to the amalgamation of Orangeville and Grand Valley as shown in Table 2.

2009 Bridge Year Comparison to 2008 Actual:

As shown in Exhibit 3, Tab 3, Schedule 1, the total other operating revenue is forecasted at $ 468,091 . The amount forecasted is $ (44,724) lower than the 2008 actual other operating revenue. The decrease was largely due to the decrease in interest rates for interest earned in our bank account and the removal of the revenues and expenses in 4375 and 4380 for the service to Grand Valley Energy further explained below in Table 2.

2009 Bridge Year Comparison to 2010 Test Year:

OHL's other operating revenue is forecast to be $ 458,139 , as shown in Exhibit 3, Tab 3, Schedule 1. The amount forecasted forecast for 2010 is $ (9,952) lower than the 2009 Test Year is due to the sale of scrap with the disposal of some old transformers and the gain on sale of a single bucket truck in 2009 compared to the amount forecasted in the 2010 Test Year.

OTHER INCOME AND EXPENSES

In Exhibit 3, Tab 3, Schedule 1, Table 1 above, the 2006 Board Approved does not reflect the 2004 activity in the 4375 and 4380 OEB accounts as the 2006 EDR Model did not treat the foregoing accounts as revenue offsets, but rather they were considered "Unclassified". For the purposes of the 2010 revenue requirement and in keeping with the 2006 EDR we have removed the revenues and expenses for performing the water/sewer billing for the Town of Orangeville and the Village of Grand Valley. OHL invoices the Town of Orangeville and the

Village of East Luther-Grand Valley at a market rate times the number of customers. The market rate was researched by polling other LDC's that bill for water and adjusted in order to obtain a profit margin between 10% and 15%. All costs for performing the work are allocated into account 4380. Further explanation of Shared Services/Corporate Cost Allocation is supplied in Exhibit 4, Tab 2 Schedule 4.

For purposes of the 2010 forward test year, we have considered the amount of $800 as forming part of the revenue offsets to our Revenue Requirement. This amount relates to the revenue and expenses for the activity of streetlight maintenance revenues $20,300 44,810 and streetlight maintenance expenses $(311,683) for which OHL should include as a revenue offset until it is determined if the LDC can continue with the maintenance contract with the Town of Orangeville and Village of Grand Valley. Further explanation of Shared Services/Corporate Cost Allocation is supplied in Exhibit 4, Tab 2 Schedule 4.

Table 2 below indicates the amount of interest that will be received on our long-term investments at the rate on the documents and our bank account interest expected calculated on our expected average bank balance calculated at 1.33%. The expected variance account carrying charges have not been included in the revenue offsets.

OTHER INCOME AND EXPENSES

Table 2

4405 - Interest and Dividend Income	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Long-term Investment Interest	684	3,839	4,849	6,300	6,300
Bank Deposit Interest	179,941	159,126	81,286	36,123	36,123
Miscellaneous Interest Revenue	53	87	29	75	
Variance Account Carrying Charges	30,228	11,148	8,532	2,387	2,387
Income Tax Adjustment			(3,245)		
Total:	**210,906**	**174,200**	**91,451**	**44,885**	**44,810**

The variance from 2006 Board Approved to 2006 actual reflects the impact of the changing position of the regulatory deferral accounts from 2004 to 2006. The decrease in interest resulted from the implementation 1590 rate recovery May 1, 2006.

Table 3

Account	Other Income and Expenses	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
4355	Gain on Disposition of Utility and Other Property	18,443	11,313	694	15,120	1,600
4360	Loss on Disposition of Utility and Other Property	(10,529)	(376)	(4,341)	0	0
4375-1	Revenue Non-Utililty Operations/Water	304,108	318,860	350,027	346,440	390,063
4375-2	Water/Sewer Penalties	0	9,155	17,660	20,000	20,300
4375-3	Revenue Non Utility Operation/Stlight Mtce	74,483	51,774	73,090	76,690	81,495
4375-4	Revenue Non-Utility/Grand Valley	84,901	176,184	211,159	0	0
4380-1	Expenses Non Utility Operation/Water	(219,491)	(222,787)	(268,297)	(285,686)	(311,683)
4380-2	Expenses Non Utility Streetlights	(65,533)	(47,006)	(65,244)	(65,244)	(66,223)
4380-3	Expenses Non Utility Grand Valley	(75,897)	(146,585)	(181,644)	0	0
4380-4	Non-Utility Expenses	0	(6,635)	(14,100)	0	0
4385	Non-Utility Rental Income	1,965	2,071	1,401	0	0
4390	Miscellaneous Non-Operating Income	14,598	10,633	15,877	17,257	500
	Total:	**127,047**	**156,602**	**136,284**	**124,577**	**116,052**

As explained previously and noteworthy in Table 3 above the revenues decline commencing 2009 due to the amalgamation of Orangeville and Grand Valley. Prior to 2009 OHL was performing management services for Grand Valley and recorded the revenues and expenses pertaining to this service in accounts 4375 and 4380.

MANAGERS SUMMARY

OVERVIEW OF OPERATING COSTS:

Operating Costs:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain OHL's distribution operations. OHL follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of OHL's operating costs for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and the 2010 Test Year including the determination of the variance amount for analysis, in accordance with the Filing Requirements, is provided in Table 1 below.

Table 1

Description	2006 Board Approved	2006 Actuals	Variance Board Approved - Actuals	2007 Actuals	Variance 2007 to 2006 Actuals	2008 Actuals	Variance 2008 to 2007 Actuals	Bridge Year 2009	Variance 2009 Bridge Year to 2008 Actuals	Test Year 2010	Test Year - Bridge Year Variance
Operation	199,733	248,806	49,073	271,145	22,339	338,920	67,775	319,390	(19,530)	408,946	89,556
Maintenance	378,794	339,366	(39,428)	445,480	106,114	457,999	12,519	447,677	(10,322)	492,423	44,746
Billing and Collections	470,174	476,660	6,486	483,587	6,927	501,713	18,126	508,659	6,946	559,953	51,294
Community Relations	24,957	151,591	126,634	168,331	16,740	42,551	(125,780)	12,584	(29,967)	28,862	16,278
Administrative and General Expenses	1,135,534	850,229	(285,304)	936,592	86,362	1,066,947	130,355	1,080,885	13,938	1,278,832	197,946
Total OM&A expenses	2,209,192	2,066,653	(142,539)	2,305,135	238,482	2,408,130	102,996	2,369,195	(38,936)	2,769,015	399,821
Variance from previous year			(142,539)		238,482		102,996		(38,936)		399,821
Percent Change (Year over Year)			-6.5%		11.5%		4.5%		-1.6%		16.9%

Percent Change Test Year Vs 2008	15.0%
Percent Change Test Year vs Last Board Approved Rebasing Year	20.2%
Average for 2006, 2007 & 2008	8.3%
Compound Annual Growth Rate (for 2006, 2007 & 2008)	7.9%

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided at Exhibit 4, Tab 2, Schedule 2.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as $50,000 (distributors with a distribution revenue requirement of less than or equal to $10 million). OHL will describe variances that are below this materiality threshold in order to create a better analysis of the activity in the OM &A accounts.

OM&A Costs:

OM&A costs in this Exhibit represent OHL's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to OHL's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2010 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

OHL is proposing recovery of 2010 Test Year OM&A costs, excluding amortization, PILs and Interest totaling $2,769,015 .

OM&A Budgeting Process Used by OHL:

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work plans:

Each Department Manager provides input for the preparation of the departmental budget. The following directives are provided to each manager and director:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budget as the base;
- Significant variances in spending from prior years must be explained and documented;
- Review the headcount of the department for accuracy and outline any changes;
- Accounting prepares a total labor budget by department using projected wage and benefit cost. Overtime and account distribution are based on previous years actual;

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

OHL 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 2 below provides a summary of 2006 OEB Approved, 2006, 2007 and 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 Exhibit 4, Tab 1, Schedule 1, Appendix A.

Table 2

Summary of Income Taxes

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Income Taxes	480,897	579,144	513,187	406,026	270,368	248,138
Large Corporation Tax	0	0	0	0	0	0
Ontario Capital Tax	37,592	24,470	11,243	4,125	4,795	2,099
Total Taxes	518,489	603,614	524,430	410,151	275,163	250,237

Orangeville Hydro Limited
EB-2009-0272
Exhibit 4
Tab 1
Schedule 1
Appendix A
Page 1 of 1
Filed: August 28, 2009

APPENDIX A

2008 Federal and Ontario Tax Return

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) **001** 86463 9562 RC0001

Corporation's name

002 Orangeville Hydro Limited

Has the corporation changed its name since the last time you filed your T2 return? **003** 1 Yes ☐ 2 No ☒

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** . . . . . **004** 1 Yes ☐ 2 No ☐

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . **010** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018)

011 400 C-Line
012 Station A Box 400
City **015** Orangeville
Province, territory, or state **016** ON
Country (other than Canada) **017** CA
Postal code/Zip code **018** L9W 2Z7

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . **020** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028)

021 c/o
022 400 C-Line
023 Station A Box 400
City **025** Orangeville
Province, territory, or state **026** ON
Country (other than Canada) **027** CA
Postal code/Zip code **028** L9W 2Z7

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . **030** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038)

031 400 C-Line
032 Station A Box 400
City **035** Orangeville
Province, territory, or state **036** ON
Country (other than Canada) **037** CA
Postal code/Zip code **038** L9W 2Z7

040 **Type of corporation at the end of the tax year**

1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2008-01-01 YYYY MM DD
Tax year-end **061** 2008-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . **065** YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒
Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☒ 2 No ☐

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091	**092**	**093**	**094**	**095**	**096**
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	☒	9
Is the corporation an associated CCPC?	160	☒	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	☒	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	☒	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	☒	3
Is the corporation claiming any type of losses?	204	☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208	☒	8
Does the corporation have any property that is eligible capital property?	210	☒	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	☒	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	☒	
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236	☐	36
Is the corporation claiming a surtax credit?	237	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238	☐	38
Is the corporation claiming a Part I tax credit?	242	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	253	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	254	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☒	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes ☐	2 No ☒

What is the corporation's major business activity? **282** ______
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Hydro Distribution	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒
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 sub-contractors during the tax year? **295** 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	1,256,204	A
Deduct: Charitable donations from Schedule 2	311	3,170			
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction *	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal		3,170	►	3,170	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				1,253,034	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	1,253,034	
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)				1,253,034	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** 1,256,204 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** 1,253,034 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000 x Number of days in the tax year in 2006 / Number of days in the tax year 366 = ... 1

400,000 x Number of days in the tax year after 2006 366 / Number of days in the tax year 366 = ... 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . . **410** 400,000 C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 x **415** *** 19,399 D / 11,250 = ... 689,742 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** F

Small business deduction

Amount A, B, C, or F whichever is the least x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366 x 16 % = 5

Amount A, B, C, or F whichever is the least x Number of days in the tax year after December 31, 2007, and before January 1, 2009 366 / Number of days in the tax year 366 x 17 % = 6

Amount A, B, C, or F whichever is the least x Number of days in the tax year after December 31, 2008 / Number of days in the tax year 366 x 17 % = 7

Total of amounts 5, 6, and 7 – enter on line 9 **430** G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . . **435** H

Amount H x Number of days in the tax year in 2006 / Number of days in the tax year 366 x 5 % = I

Amount H x Number of days in the tax year in 2007 / Number of days in the tax year 366 x 7 % = J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J . . . . **438** K
Enter amount K on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		1,253,034	A
Amount Z1 from Part 9 of Schedule 27			B
Amount QQ from Part 13 of Schedule 27			C
Taxable resource income from line 435			D
Amount used to calculate the credit union deduction from Schedule 17			E
Amount from line 400, 405, 410, or 425, whichever is the least			F
Aggregate investment income from line 440			G
Total of amounts B, C, D, E, F, and G	▶		H
Amount A **minus** amount H (if negative, enter "0")		1,253,034	I

Amount I	1,253,034	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	1,253,034	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=	106,508	K
Amount I	1,253,034	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	1,253,034	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 . . . 106,508 M

Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)			N
Amount Z1 from Part 9 of Schedule 27			O
Amount QQ from Part 13 of Schedule 27			P
Taxable resource income from line 435			Q
Amount used to calculate the credit union deduction from Schedule 17			R
Total of amounts O, P, Q, and R	▶		S
Amount N **minus** amount S (if negative, enter "0")			T

Amount T		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	7 %	=		U
Amount T		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=		V
Amount T		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=		W
Amount T		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=		W1

General tax reduction – Total of amounts U, V, W, and W1 . . . X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income 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 1,253,034

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 = ______

______ ▶ ______

1,253,034

x 26 2 / 3 % = 334,142 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) 244,342

Deduct: Corporate surtax from line 600 . . . . ______

Net amount . . . . 244,342 ▶ 244,342 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 . . . . 276,716 x 1 / 3 92,239 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**	476,153	A

Corporate surtax calculation

Base amount from line A above	476,153	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	125,303	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	125,303	7
Net amount (line 1 **minus** line 7)	350,850	8

Corporate surtax*

Line 8 350,850 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	1,253,034		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	1,253,034 ▶	1,253,034	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)		476,153	E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	**608**	125,303	
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**	106,508	
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		231,811 ▶	

	231,811	F
Part I tax payable – Line E **minus** line F	244,342	G

Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	244,342
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		244,342

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . **750** Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
			▶
Total tax payable	770		244,342 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	244,342
Total credits	890	244,342 ▶ 244,342 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** Dick (Last name in block letters) **951** George (First name in block letters) **954** President (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009-08-25 Date (yyyy/mm/dd) ________ Signature of the authorized signing officer of the corporation **956** (519) 942-8000 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 Janet Howard (Name in block letters) **959** (519) 942-8000 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: Jan Howard
Telephone number: (519) 942-8000

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	244,342

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 244,342 **A**

Total instalments credited to the taxation year per T9 244,342 **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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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	6,362,962	
	Total tangible capital assets	2008	+	28,404,960	
	Total accumulated amortization of tangible capital assets	2009	–	14,945,573	
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	65,000	
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	19,887,349	
	Liabilities				
	Total current liabilities	3139	+	3,629,376	
	Total long-term liabilities	3450	+	8,015,367	
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	11,644,743	
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	8,242,606	
	Total liabilities and shareholder equity	3640	=	19,887,349	
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	427,071	

CORPORATE TAXPREP / TAXPREP DES SOCIÉTÉS - EP10 VERSION 2008 V2.0

* Generic item

Attached Schedule with Total

GIFI code 1060 – Accounts receivable

Title GIFI code 1060 – Accounts receivable

Description	Amount	
Accounts receivable	2,851,736	00
Accrued unbilled revenue	1,628,805	00
Total	4,480,541	00

Attached Schedule with Total

GIFI code 1901 – Accumulated amortization of other tangible capital assets

Title GIFI code 1901 – Accumulated amortization of other tangible capital assets

Explanatory note

See FS

Description	**Amount**	
Total accumulated amortization	14,945,573	00
Building	-772,025	00
Total	14,173,548	00

Attached Schedule with Total

Tangible capital property – GIFI code 1900 – Other tangible capital assets

Title Tangible capital property – GIFI code 1900 – Other tangible capital assets

Explanatory note

See U.2.1

Description	**Amount**	
Total cost	28,404,960	00
Land	-173,526	00
Building	-2,727,221	00
Total	25,504,213	00

Attached Schedule with Total

Tangible capital assets – GIFI code 1600 – Land

Title Tangible capital assets – GIFI code 1600 – Land

Description	**Amount**	
Total land	198,738	71
Land rights net of amortization	-25,212	25
Total	173,526	46

Attached Schedule with Total

GIFI code 3320 – Other long-term liabilities

Title GIFI code 3320 – Other long-term liabilities

Description	Amount	
Regulatory liabilities	1,255,408	00
Post-employement benefits	188,898	00
Consumer deposits	524,262	00
Total	1,968,568	00

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 RC0001	2008-12-31

Income statement information

Description	GIFI	
Operating name	**0001**	
Description of the operation	**0002**	
Sequence Number	**0003**	01

Income statement information

Account	Description	GIFI		Current year	Prior year
	Total sales of goods and services	**8089**	+	21,670,196	
	Cost of sales	**8518**	–	17,524,426	
	Gross profit/loss	**8519**	=	4,145,770	
	Cost of sales	**8518**	+	17,524,426	
	Total operating expenses	**9367**	+	3,543,376	
	Total expenses (mandatory field)	**9368**	=	21,067,802	
	Total revenue (mandatory field)	**8299**	+	22,117,896	
	Total expenses (mandatory field)	**9368**	–	21,067,802	
	Net non-farming income	**9369**	=	1,050,094	

Farming income statement information

Account	Description	GIFI		Current year	Prior year
	Total farm revenue (mandatory field)	**9659**	+		
	Total farm expenses (mandatory field)	**9898**	–		
	Net farm income	**9899**	=		

Account	Description	GIFI		Current year	Prior year
	Net income/loss before taxes and extraordinary items	**9970**	=	1,050,094	

Extraordinary items and income (linked to Schedule 140)

Account	Description	GIFI		Current year	Prior year
	Extraordinary item(s)	**9975**	–		
	Legal settlements	**9976**	–		
	Unrealized gains/losses	**9980**	+		
	Unusual items	**9985**	–		
	Current income taxes	**9990**	–	406,026	
	Deferred income tax provision	**9995**	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	**9999**	=	644,068	

Attached Schedule with Total

GIFI code 9270 – Amount – Other expenses

Title GIFI code 9270 – Amount – Other expenses

Description	Amount	
Distribution	765,956	00
Billing and collection	437,086	00
Financial	409,882	00
Total	1,612,924	00

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Orangeville Hydro Limited	86463 9562 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 ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes ☐ 2 No ☒

* 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 ☒

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 ☒

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 ☒ 2 No ☐

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes ☐ 2 No ☒

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes ☒ 2 No ☐

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes ☒ 2 No ☐

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes ☒ 2 No ☐

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes ☐ 2 No ☒

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

Notes

Name: **Orangeville Hydro Limited**

BN: 86463 9562 RC 0001 **Taxation Year End:** **2008-12-31**

Notes to follow by fax.

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
Orangeville Hydro Limited	86463 9562 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				644,068	A
Add:					
Provision for income taxes – current	101	406,026			
Amortization of tangible assets	104	1,004,608			
Amortization of intangible assets	106	1,353			
Loss on disposal of assets	111	3,647			
Charitable donations and gifts from Schedule 2	112	3,170			
Non-deductible meals and entertainment expenses	121	2,883			
Subtotal of additions		1,421,687	▶	1,421,687	
Other additions:					
Miscellaneous other additions:					
600 Post Employment Expense In Excess Of Payment	290	36,567			
601 Transition Costs Deducted In Prior Years	291	27,654			
Subtotal of other additions	199	64,221	▶	64,221	
Total additions	500	1,485,908	▶	1,485,908	
Deduct:					
Capital cost allowance from Schedule 8	403	861,913			
Cumulative eligible capital deduction from Schedule 10	405	10,117			
Subtotal of deductions		872,030	▶	872,030	
Other deductions:					
Miscellaneous other deductions:					
700 Refund of prior year non-deductible interest	390	1,742			
Total	394				
Subtotal of other deductions	499	1,742	▶	1,742	
Total deductions	510	873,772	▶	873,772	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,256,204	

* For reference purposes only

T2 SCH 1 E (08)

Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

Description	**Amount**	
Post-employement benefits, current year	188,898	00
Post-employement benefits, prior year	-152,331	00
Total	36,567	00

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SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Orangeville Hydro Limited	86463 9562 RC0001	2008-12-31

- For use by corporations to claim any of the following:
  - – charitable donations;
  - – gifts to Canada, a province, or a territory;
  - – gifts of certified cultural property;
  - – gifts of certified ecologically sensitive land; or
  - – additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - – Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - – If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Headwaters Health Care Foundation	500
Canadian Cancer Society	500
The Princess Margaret Hospital Foundation	500
Community Living Dufferin	500
Dufferin Child and Family Services	400
The Kinette Club of Orangeville	120
Big Brothers and Big Sisters	150
Family Transition Place	500
Subtotal	3,170
Add: Total donations of less than $100 each	
Total donations in current tax year	3,170

			Federal	**Quebec**	**Alberta**
Charitable donations at the end of the previous tax year					
Deduct: Charitable donations expired after five tax years	239				
Charitable donations at the beginning of the tax year	240				
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210	3,170			
Subtotal (line 250 **plus** line 210)			3,170	3,170	3,170
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available			3,170 A	3,170	3,170
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260		3,170	3,170	3,170
Charitable donations closing balance	280				

Amounts carried forward – Charitable donations

Year of origin:		**Federal**	**Quebec**	**Alberta**
1st prior year	2007			
2nd prior year	2006			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2003			
6th prior year *	2002			
Total (to line A)				

***** These donations expired in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %			942,153	B
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **	225		C	
Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01)	227		D	
The amount of the recapture of capital cost allowance in respect of charitable gifts	230			
Proceeds of disposition, less outlays and expenses **			E	
Capital cost **			F	
Amount E or F, whichever is less	235			
Amount on line 230 or 235, whichever is less			G	
Subtotal (**add** amounts C, D, and G)			H	
Amount H **multiplied** by 25 %				I
Subtotal (amount B**plus** amount I)			942,153	J
Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less)			3,170	K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		►
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory *	310		
Subtotal (line 350**plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	355		
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).	360		
Gifts to Canada, a province, or a territory closing balance	380		

***** Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Quebec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Quebec	Alberta
1st prior year	2007			
2nd prior year	2006			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2003			
6th prior year *	2002			
Total				

***** These donations expired in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Quebec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Quebec	Alberta
1st prior year	2007			
2nd prior year	2006			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2003			
6th prior year *	2002			
Total				

***** These donations expired in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal		Quebec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year							
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640						
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Quebec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

		Federal	Quebec	Alberta
Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Quebec	Alberta
1st prior year	2007			
2nd prior year	2006			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2003			
6th prior year *	2002			
Total				

***** These donations expired in the current year.

Canada

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 RC0001	2008-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

		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					
				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 400	Business Number 410	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430
1				

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

Total taxable dividends paid in the taxation year to other than connected corporations	450	276,716
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	276,716

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above)		460	276,716
Other dividends paid in the taxation year (total of 510 to 540)			
Total dividends paid in the taxation year		500	276,716
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			276,716

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 RC0001	2008-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number **200**	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Net adjustments** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1	1	Building/Former Elect Distributio	12,234,215	109,490		0	54,745	12,288,960	4	0	0	491,558	11,852,147
2	8	Equipment	101,369	19,930		0	9,965	111,334	20	0	0	22,267	99,032
3	10	Trucks	289,025			694		288,331	30	0	0	86,499	201,832
4	12	Computer Software	15,273	50,753		0	25,377	40,649	100	0	0	40,649	25,377
5	45	Computer Equipment	16,333			0		16,333	45	0	0	7,350	8,983
6	47	Elect Distribution Equip	2,049,972	1,049,711		0	524,856	2,574,827	8	0	0	205,986	2,893,697
7	50	Computer Equipment	9,436	8,778		0	4,389	13,825	55	0	0	7,604	10,610
		Total	14,715,623	1,238,662		694	619,332	15,334,259				861,913	15,091,678

* 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.

Canada

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 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.	Orangeville Hydro Services Inc.		89454 8015 RC0001	3					
2.	Orangeville Railway Development C		86433 3166 RC0001	3					
3.	Town of Orangeville		10698 6151 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

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 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** 144,533 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** 144,533 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) . . . . 144,533 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 144,533

less amount from line 249 ______

Current year deduction . . . . 144,533 x 7.00 % = **250** 10,117 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 10,117 ▶ 10,117 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 134,416 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.

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 x 1 / 2 = Q

Line P minus line Q (if negative, enter "0") . . . . R

Amount R x 2 / 3 = S

Amount N or amount O, whichever is less . . . . T

Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1) **410**

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SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 RC0001	2008-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	99,037	421091			

Note 1: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule .... 99,037 **A**

Less:

Total of all amounts for deferred income plans deducted in your financial statements .... 99,037 **B**

Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0") .... **C**

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by:
1 – Trustee
2 – Employer

Canada

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2008

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 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	Orangeville Hydro Limited	86463 9562 RC0001	1	400,000	100.0000	400,000	
2	Orangeville Hydro Services Inc.	89454 8015 RC0001	1	400,000			
3	Orangeville Railway Development Corp.	86433 3166 RC0001	1	400,000			
4	Town of Orangeville	10698 6151 RC0001	4	400,000			
				Total	100.0000	400,000	**A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

Canada

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Orangeville Hydro Limited	86463 9562 RC0001	2008-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Provide only one number per shareholder

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	**200**	**300**	**350**	**400**	**500**
1	The Corporation of the Town of Orangeville	10698 6151 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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
Orangeville Hydro Limited	86463 9562 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 . . .		276,716		
Total taxable dividends paid in the tax year	100	276,716		
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	
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.

Canada

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☒ Yes ☐ No

Page 1 of 20

Corporation's Legal Name *(including punctuation)*
Orangeville Hydro Limited

Ontario Corporations Tax Account No. (MOF)
1800151

This Return covers the Taxation Year
Start (year month day): 2008-01-01
End (year month day): 2008-12-31

Mailing Address
400 C-Line
Station A Box 400
Orangeville
ON CA L9W 2Z7

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): 2000-09-11

Registered/Head Office Address
400 C-Line
Station A Box 400
Orangeville
ON CA L9W 2Z7

Ontario Corporation No. (MGS): 1438531

Location of Books and Records
CORPORATE TAXPREP - 2007 CT23 - 2008 V.2 - 080A
400 C-Line
Station A Box 400
Orangeville
ON CA L9W 2Z7

Canada Revenue Agency Business No.
If applicable, enter
86463 9562 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Janet Howard	(519) 942-8000	(519) 941-6061

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*

Ministry Use

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s):

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ ☒ **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)*
George Dick

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
Orangeville Hydro Limited	1800151	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 ☒ Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
2 ☐ Other Private
3 ☐ Public
4 ☐ Non-share Capital
5 ☐ Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 ☐ Family Farm corporation s.1(2)
2 ☐ Family Fishing corporation s.1(2)
3 ☐ Mortgage Investment corporation s.47
4 ☐ Credit Union s.51
5 ☐ Bank Mortgage subsidiary s.61(4)
6 ☐ Bank s.1(2)
7 ☐ Loan and Trust corporation s.61(4)
8 ☐ Non-resident corporation s.2(2)(a) or (b)
9 ☐ Non-resident corporation s.2(2)(c)
10 ☐ Mutual Fund corporation s.48
11 ☐ Non-resident owned Investment corporation s.49
12 ☐ Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
14 ☐ Bare Trustee corporation
15 ☐ Branch of Non-resident s.63(1)
16 ☐ Financial institution prescribed by Regulation only
17 ☐ Investment Dealer
18 ☐ Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
19 ☒ Hydro successor, municipal electrical utility or subsidiary of either
20 ☐ Producer and seller of steam for uses other than for the generation of electricity
21 ☐ Insurance Exchange s.74.4
22 ☐ Farm Feeder Finance Co-operative corporation
23 ☐ Professional corporation (incorporated professionals only)

CORPORATE TAXPREP - 2007 CT23 - 2008 V.2 - 080A

☐ This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

☐ Amended Return

☐ Taxation year end change – Canada Revenue Agency approval required

☐ Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

☒ Final taxation year before amalgamation

☐ The corporation has a floating fiscal year end

☐ There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

☐ There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired year month day

☐ The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

☐ First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

☐ Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
☐	☒	Was the corporation inactive throughout the taxation year?
☒	☐	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
☐	☒	the Carry-back of a Loss?
☒	☐	an Overpayment?
☐	☒	a Specified Refundable Tax Credit?
☐	☒	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	1,256,204
Subtract: Charitable donations	–	1	3,170
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 From 715 (page 16) ______ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	1,253,034

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 1,253,034

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) 1,253,034 x 30 100.0000 % Ontario Allocation x 12.5 % x Days after Dec. 31, 2002 and before Jan. 1, 2004 33 ______ ÷ Total Days 73 366 = + 29 ______

From 10 (or 20 if applicable) 1,253,034 x 30 100.0000 % Ontario Allocation x 14 % x Days after Dec. 31, 2003 34 366 ÷ Total Days 73 366 = + 32 175,425

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 175,425

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

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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) ☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))				50	1,256,204
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51	1,253,034		
Add: Losses of other years deducted for federal purposes (fed.s.111)	+	52			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	–	53			
	=		1,253,034	54	1,253,034
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000		

Ontario Business Limit Calculation

320,000 x Days after Dec. 31, 2002 and before Jan. 1, 2004 31 ______ ÷ ** 366 = + 46 ______

400,000 x Days after Dec. 31, 2003 34 366 ÷ ** 366 = + 47 ______

Business Limit for Ontario purposes 46 + 47 = 44 500,000 x Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated. 48 100.0000 % = 45 500,000

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 500,000 = 60 500,000

56: Least of 50, 54 or 45

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate 7 % x [31] Days after Dec. 31, 2002 and before Jan. 1, 2004 ______ ÷ [73] Total Days 366 = + [89] .

8.5 % x [34] Days after Dec. 31, 2003 366 ÷ [73] Total Days 366 = + [90] 8.5000

IDSBC Rate for Taxation Year [89] + [90] = [78] 8.5000

Claim From [60] 500,000 x From [78] 8.5000 % = [70] 42,500

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 500,000 in [114] below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** From [10] (or [20] if applicable) + [80] 1,253,034

If you are a member of an associated group (X) [81] ☒ (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)
Orangeville Hydro Services Inc.	1800152	2008-12-31	+ [82]	
Orangeville Railway Development Corp.	7244292	2008-12-31	+ [83]	
Town of Orangeville		2008-12-31	+ [84]	

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Aggregate Taxable Income [80] + [82] + [83] + [84] , etc. = [85] 1,253,034

Number of Days in Taxation Year

320,000 x [31] Days after Dec. 31, 2002 and before Jan. 1, 2004 ______ ÷ [73] Total Days 366 = + [115]

400,000 x [34] Days after Dec. 31, 2003 366 ÷ [73] Total Days 366 = + [116]

[115] + [116] = 500,000 ▶ – [114] 500,000

(If negative, enter nil) = [86] 753,034

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax 4.6670 % x [38] Days after Dec. 31, 2002 ______ ÷ [73] Total Days 366 = + [97] 4.2500

From [86] 753,034 x From [97] 4.2500 % = [87] 32,004

From [87] 32,004 x From [60] 500,000 ÷ From [114] 500,000 = [88] 32,004

Surtax Lesser of [70] or [88] = [100] 32,004

**** 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

DOLLARS ONLY

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 32,004 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 376,518

*Ontario Allocation

Lesser of 56 or 121 + 122 376,518

120 – 56 + 122 = 130

Taxable Income + From 10 1,253,034

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 122 376,518

Subtract: Taxable Income 10 1,253,034 X Allocation % to jurisdictions outside Canada – 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses – 141

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10 – 56 + 122 – 140 – 141 = 142 1,129,552

Claim

Number of Days in Taxation Year

143 x From 30 100.0000 % x 1.5 % x Days after Dec. 31, 2002 and before Jan. 1, 2004 33 ÷ Total Days 73 366 = + 154

Lesser of 130 or 142 Ontario Allocation

143 x From 30 100.0000 % x 2 % x Days after Dec. 31, 2003 34 366 ÷ Total Days 73 366 = + 156

Lesser of 130 or 142 Ontario Allocation

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 = 190 164,929

continued on Page 7

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	2008-12-31

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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)

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.

No. of Graduates From 6596 194

Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) - - - - - - - - - - - - - - - + 195 .

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)

Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* - - + 196 .

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)

Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) - + 197 .

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)

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)

Applies to employment of eligible apprentices.

No. of Apprentices From 5896 202

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)* - - - - = 230 164,929 .

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	19,887,349
Total Revenue of the corporation	+ 241	22,117,896

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 ☒ (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
Orangeville Hydro Services Inc.	1800152	2008-12-31	+ 243	65,601	+ 244	
			+ 245		+ 246	
			+ 247		+ 248	

Aggregate Total Assets	240 + 243 + 245 + 247 , etc.	= 249	19,952,950
Aggregate Total Revenue	241 + 244 + 246 + 248 , etc.	= 250	22,117,896

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 1,050,094 x From 30 100.0000 % X 4 % = 276 42,004

If negative, enter zero — Ontario Allocation

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Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	–	277	
Subtract: Income Tax	–	From 190	164,929
Net CMT Payable (If negative, enter Nil on Page 17.)	=	280	-122,925

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	164,929
Gross CMT Payable	+ From 276	42,004			
Subtract: Foreign Tax Credit for CMT purposes	– From 277				
If 276 – 277 is negative, enter NIL in 290	=	42,004	–	290	42,004
Income Tax eligible for CMT Credit			=	300	122,925

B.

Income Tax (after deduction of specified credits)	+	From 230	164,929
Subtract: CMT credit used to reduce income taxes	–	310	
Income Tax	=	320	164,929

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
Orangeville Hydro Limited	1800151	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	7,815,535
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	427,071
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	6,792,802
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	
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	1,852,971
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	16,888,379
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	16,888,379
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	16,888,379

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	65,000
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	65,000

continued on Page 10

Total Assets (Int.B. 3015R)

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Total Assets per balance sheet	+	420	19,887,349 •
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	19,887,349 •
Amounts in 360 and 361 (if deducted from assets)	+	440	•
Subtract: Amounts in 371 , 372 and 381	–	441	•
Subtract: Appraisal surplus if booked	–	442	•
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	•
Total Assets	=	450	19,887,349 •

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	=	460	55,198 •
Taxable Capital 390 – 460	=	470	16,833,181 •

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	22,117,896 •
Total Assets (as adjusted)	From 430	19,887,349 •

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

		Number of Days			Total Days			
		Days after Dec. 31, 2004 and before Jan. 1, 2006						
7,500,000	x	36	÷	73	366	= +	501	•
		Days after Dec. 31, 2005 and before Jan. 1, 2007						
10,000,000	x	37	÷	73	366	= +	502	•
		Days after Dec. 31, 2006 and before Jan. 1, 2008						
12,500,000	x	38	÷	73	366	= +	504	•
		Days after Dec. 31, 2007						
15,000,000	x	39 366	÷	73	366	= +	505	15,000,000 •

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 15,000,000 •

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

		Number of Days			Total Days			
		Days before Jan. 1, 2007						
0.3 %	x	556	÷	73	366	= +	511	%
		Days after Dec. 31, 2006 and before Jan. 1, 2009						
0.225 %	x	557 366	÷	73	366	= +	512	0.2250 %

Capital Tax Rate 511 + 512 = 516 0.2250 %

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Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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.

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D2. ☒ 524 (X if applicable) One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation

Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - + From 470 16,833,181 •

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
Orangeville Hydro Services Inc.	1800152	2008-12-31	+ 531	•
Orangeville Railway Development Corp.	7244292	2008-12-31	+ 532	•
Town of Orangeville		2008-12-31	+ 533	•

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - - - - - - - - - - - - - - - - - - - = 540 16,833,181 •

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 16,833,181 • ÷ From 540 16,833,181 • x From 503 15,000,000 • = 541 15,000,000 •

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

☐ 591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+ From 470 16,833,181 •
– 542 15,000,000 •
= 471 1,833,181 • 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 4,125 • **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 • x From 30 100.0000 % Ontario Allocation x From 516 0.2250 % Capital Tax Rate - - - - - - - = + 561 •

– Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - – From 995 •
= 562 •

Capital Tax - - - - - - - - - 562 • x 555 366 Days in taxation year / * 366 (366 if leap year) - - - - - - = 563 • **Total Capital Tax for the taxation year**

Transfer to 543 *and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits - = 543 4,125 •

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - - - - - - - – 546 •

Capital Tax 543 – 546 *(amount cannot be negative)* - - - - - - - - - - - - - - - - - - - = 550 4,125 •

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ______ x 567 ____% x From 30 100.0000 % x 555 366 / * 366 (366 if leap year) = + 569 ______

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 | Capital Tax Rate (1) *(Refer to Guide)* | Ontario Allocation | Days in taxation year

570 ______ x 571 ____% x From 30 100.0000 % x 555 366 / * 366 (366 if leap year) = + 574 ______

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount | Capital Tax Rate (2) *(Refer to Guide)* | Ontario Allocation | Days in taxation year

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) 569 + 574 = 575 ______

** If floating taxation year, refer to Guide.*

CORPORATE TAXPREP - 2007 CT23 - 2008 V.2 - 080A

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 1,256,204 ●
Transfer to Page 15

Add:

Federal capital cost allowance	+	601	861,913 ●
Federal cumulative eligible capital deduction	+	602	10,117 ●
Ontario taxable capital gain	+	603	●
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) ÷ 73 366 (Total Days) =+ 633 ●

612 ● x 5 / 14 x 34 366 (Days after Dec. 31, 2003) ÷ 73 366 (Total Days) =+ 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 - - - = 872,030 ● ▶ 640 872,030 ●
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+	650	861,913 ●
Ontario cumulative eligible capital deduction	+	651	10,117 ●
Federal taxable capital gain	+	652	●
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 - - - - - - - - 681 872,030 ●
Transfer to Page 15

continued on Page 15

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 1,256,204 •

Total of Additions on page 14 - From = 640 872,030 •

Sub Total of deductions on page 14 - From = 681 872,030 •

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 = 872,030 • ▶ 680 872,030 •

Net income (loss) for Ontario Purposes 600 + 640 – 680 - - - - - - - - - - - - - - - - - - - = 690 1,256,204 •

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	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)	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	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day		Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 2000-09-30	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2001-09-30	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2001-12-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2002-12-31	820	830	840	853	873
804	5th preceding taxation year 2003-12-31	821	831	841	854	874
805	4th preceding taxation year 2004-12-31	822	832	842	855	875
806	3rd preceding taxation year 2005-12-31	823	833	843	856	876
807	2nd preceding taxation year 2006-12-31	824	834	844	857	877
808	1st preceding taxation year 2007-12-31	825	835	845	858	878
809	Current taxation year 2008-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(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.

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

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Summary

Income Tax	+ From 230 or	320	164,929 •
Corporate Minimum Tax	+ From	280	•
Capital Tax	+ From	550	4,125 •
Premium Tax	+ From	590	•
Total Tax Payable	=	950	169,054 •
Subtract: Payments	–	960	315,658 •
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	-146,604 •
If payment due	Enclosed *	990	•
If overpayment: Refund *(Refer to Guide)*	=	975	146,604 •
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)*
George Dick

Title
President

Full Residence Address

Signature

Date
2009-08-25

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

Explanatory note

See FF.9

Description	**Amount**	
NBV capital assets	-13,459,387	00
Land	198,739	00
Inventory included in capital assets	296,963	00
UCC	15,091,678	00
UCC on uplift	-579,426	00
Cummulative CEC deduction	-89,438	00
Accum amort re CEC property	13,542	00
CEC property expensed for accounting	265,743	00
Permanent difference on CEC property	-74,341	00
Pension liability	188,898	00
Total	1,852,971	00

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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	644,068
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	+ 2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102			
Equity income from corporations	+ 2103			
Share of partnership(s)/joint venture(s) income	+ 2104			
Dividends received/receivable deductible under fed.s.112	+ 2105			
Dividends received/receivable deductible under fed.s.113	+ 2106			
Dividends received/receivable deductible under fed.s.83(2)	+ 2107			
Dividends received/receivable deductible under fed.s.138(6)	+ 2108			
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) ______ x 3	+ 2109			
Subtotal	=		– 2110	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	+ 2111	406,026		
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	=	406,026	+ 2116	406,026

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85	+ 2117		or – 2118	
** Fed.s.85.1	+ 2119		or – 2120	
** Fed.s.97	+ 2121		or – 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or – 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125		or – 2126	
** Amounts relating to s.57.10 election/regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127		or – 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			– 2150	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			– 2155	

Subtotal (Additions) =			+ 2129	
Subtotal (Subtractions)	=		– 2130	
** Other adjustments			± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131			= 2132	1,050,094
** 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	1,050,094
Deduct: * CMT losses: pre-1994 Loss	+ From 2210			
* CMT losses: other eligible losses	+ 2211			
	=		– 2135	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base	= 2136	1,050,094

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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 **NOTE (3)** . . . . + 2203

Losses from predecessor corporations on wind-up **NOTE (3)** . . . + 2204

Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes

Subtotal . . . . = ▶ + 2207

Adjustments (attach schedule) . . . . ± 2208

CMT losses available 2201 + 2207 ± 2208 . . . . = 2209

Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income . . . . + 2210

Other eligible losses utilized during the year to reduce adjusted net income **NOTE (4)** . . . . + 2211

Losses expired during the year . . . . + 2212

Subtotal . . . . = ▶ – 2213

Balances at End of Year **NOTE (5)** 2209 – 2213 . . . . = 2214

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

CORPORATE TAXPREP - 2008 V.2

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209 .

(5) Amount in 2214 must equal sum of 2270 + 2290 .

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 2000-09-30	2260	2280
2241	8th preceding taxation year 2001-09-30	2261	2281
2242	7th preceding taxation year 2001-12-31	2262	2282
2243	6th preceding taxation year 2002-12-31	2263	2283
2244	5th preceding taxation year 2003-12-31	2264	2284
2245	4th preceding taxation year 2004-12-31	2265	2285
2246	3rd preceding taxation year 2005-12-31	2266	2286
2247	2nd preceding taxation year 2006-12-31	2267	2287
2248	1st preceding taxation year 2007-12-31	2268	2288
2249	Current taxation year 2008-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214 .

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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 to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390 .

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 2000-09-30	2360	2380
2341	8th preceding taxation year 2001-09-30	2361	2381
2342	7th preceding taxation year 2001-12-31	2362	2382
2343	6th preceding taxation year 2002-12-31	2363	2383
2344	5th preceding taxation year 2003-12-31	2364	2384
2345	4th preceding taxation year 2004-12-31	2365	2385
2346	3rd preceding taxation year 2005-12-31	2366	2386
2347	2nd preceding taxation year 2006-12-31	2367	2387
2348	1st preceding taxation year 2007-12-31	2368	2388
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. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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	 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						
9th Prior Year	2000-09-30					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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						
9th Prior Year	2000-09-30					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Ontario **Ministry of Revenue**
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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 consumer deposits	+	25,000
Current portion of long-term debt	+	196,741
Consumer deposits	+	524,262
Long-term debt	+	6,046,799
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	6,792,802

Ontario

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Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Orangeville Hydro Limited	1800151	2008-12-31

- For use by a corporation to claim any of the following:
  - Charitable donations;
  - Gifts to Her Majesty in right of Ontario, to Ontario crown agencies, or to Ontario Crown foundations;
  - Gifts to Canada or a province;
  - Gifts of certified cultural property; or
  - Gifts of certified ecologically sensitive land.
- The donations and gifts are eligible for a five year carry-forward.
- Use this schedule to show a credit transfer following an amalgamation or wind-up of subsidiary as described under subsection 87(1) and 88(1) of the federal *Income Tax Act* (Canada).
- For donations and gifts made after March 22, 2004, subsection 34(1.1) of the *Corporations Tax Act* parallels subsection 110.1(1.2) of the *Income Tax Act* and provides as follows:
  - where a particular corporation has undergone a change of control, for taxation years that end on or after the change of control, no corporation can claim a deduction for a gift made by a particular corporation to a qualified donee before the change of control;
  - if a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the change of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- For instructions on calculating additional deductions for eligible medical gifts made after March 18, 2007, please see the Revised Guide to the 2007 CT23 Corporations Tax and Annual Return. The deduction may be claimed in box 664 of Ontario Schedule 1.
- File one completed copy of this schedule with your CT23.

Part 1 – Charitable Donations

Charitable Donations at end of preceding taxation year			+	A
Deduct: Donations expired after 5 taxation years			–	B
Charitable donations at beginning of taxation year			=	C
Add: Donations transferred on amalgamation or wind-up of subsidiary	+	D		
Total current year charitable donations made	+	3,170 E		
Subtotal D + E	=	3,170	▶	3,170 F
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)			–	G
Total donations available **C + F – G**			=	3,170 H
Deduct: Amount applied against taxable income (amount **U**, Part 2)			–	3,170 U
Charitable donations closing balance			=	I

Part 2 – Maximum Deduction Calculation for Donations

Ontario net income for tax purposes multiplied by 75%					=	942,153 J

Note: *For credit unions the Ontario net income for tax purposes is the amount before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.*

Ontario taxable capital gains arising in respect of gifts of capital property			+	K		
Ontario taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ITA			+	L		
Add the lesser of:						
1. The amount of the recapture of capital cost allowance in respect of charitable gifts		M				
2. **The lesser of:**						
2a. Proceeds of dispositions less outlays and expenses	N					
2b. The capital cost	O					
The lesser of **N** and **O**	▶	P				
The lesser of **M** and **P**			▶ +	Q		
Subtotal K + L + Q			=	R		
25% X	R				=	S
Maximum deduction allowable J + S					=	942,153 T
Claim for charitable donations (not exceeding the lesser of **H** from Part 1, **T** and net income for tax purposes)						3,170 U

Enter in 1 *of the CT23*

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Orangeville Hydro Limited	1800151	2008-12-31

Part 3 – Gifts to Her Majesty in right of Ontario

For use by a corporation claiming gifts to Her Majesty in right of Ontario, to Ontario Crown Agencies, or to Ontario Crown Foundations.

Gifts to Ontario Crown Agency or Ontario Crown Foundation at end of the preceding taxation year . . . . +

Deduct: Gifts expired after 5 years . . . . –

Gifts to Ontario Crown Agency or Ontario Crown Foundation at the beginning of the taxation year . . . . =

Add: Gifts transferred on amalgamation or wind-up of a subsidiary . . . . +

Total current year gifts . . . . +

Subtotal . . . . = ▶

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) . . . . –

Total gifts available . . . . =

Deduct: Amount applied against taxable income 2 of the CT23 . . . . –

Gifts to Ontario Crown Agency or Ontario Crown Foundation closing balance . . . . =

Foundation Name	Date of Donation	Amount $

Total gifts to Her Majesty in right of Ontario . . . . =

Part 4 – Maximum Deduction Calculation for Gifts to Her Majesty in Right of Ontario

Deduction is the lesser of:

1. Ontario Net Income before deductions of gifts after deducting charitable donations and gifts to Her Majesty in right of Canada or a province other than Ontario . . . . 1,253,034 **V**
2. **Lesser of:**
   - 2a. Ontario Net Income for the taxation year . . . . 1,256,204 **W**
   - 2b. Gifts made in the taxation year or any of the five preceding taxation years to Her Majesty in Right of Ontario, an Ontario Crown Agency or an Ontario Crown Foundation . . . . **X**

The lesser of **W** and **X** . . . . ▶ **Y**

Maximum deduction allowable the lesser of **V** and **Y** . . . . **Z**

Transfer to 2 *of the CT23*

Part 5 – Gifts to Canada or a province other than Ontario

Gifts to Canada or a province other than Ontario at the end of the preceding year . . . . +

Deduct: Gifts to Canada or a province other than Ontario expired after five taxation years . . . . –

Gifts to Canada or a province other than Ontario at the beginning of the taxation year . . . . =

Add: Gifts to Canada or a province other than Ontario transferred on amalgamation or wind-up of a subsidiary . . . . +

Total current year Gifts to Canada or a province other than Ontario *(Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date.)* . . . . +

Subtotal . . . . = ▶

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) . . . . –

Total gifts to Canada or a province other than Ontario available . . . . =

Deduct: Amount applied against taxable income . . . . –

Gifts to Canada or a province other than Ontario closing balance . . . . =

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Orangeville Hydro Limited	1800151	2008-12-31

Part 6 – Gifts of certified cultural property

Gifts of certified cultural property at the end of the preceding taxation year . . . . +

Deduct: Gifts of certified cultural property expired after five years . . . . –

Gifts of certified cultural property at the beginning of the taxation year . . . . =

Add: Gifts of certified cultural property transferred on amalgamation or wind-up of a subsidiary . . . . +

Total current year gifts of certified cultural property . . . . +

Subtotal . . . . = ▶

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) . . . . –

Total gifts of certified cultural property available . . . . =

Deduct: Amount applied against taxable income . . . . –

Gifts of certified cultural property closing balance . . . . =

Part 7 – Gifts of certified ecologically sensitive land

Gifts of certified ecologically sensitive land at the end of the preceding taxation year . . . . +

Deduct: Gifts of certified ecologically sensitive land expired after five years . . . . –

Gifts of certified ecologically sensitive land at the beginning of the taxation year . . . . =

Add: Gifts of certified ecologically sensitive land transferred on amalgamation or wind-up of a subsidiary . . . . +

Total current year gifts of certified ecologically sensitive land . . . . +

Subtotal . . . . = ▶

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) . . . . –

Total gifts of certified ecologically sensitive land available . . . . =

Deduct: Amount applied against taxable income . . . . –

Gifts of certified ecologically sensitive land closing balance . . . . =

Part 8 – Analysis of balance by year of origin

Year of origin	Charitable donations	Gifts to Her Majesty in right of Ontario	Gifts to Canada or a province other than Ontario	Gifts of certified cultural property	Gifts of certified ecologically sensitive land
2007-12-31					
2006-12-31					
2005-12-31					
2004-12-31					
2003-12-31					
2002-12-31					
Totals					

Ministry of Revenue
Corporations Tax
33 King Street West
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Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Orangeville Hydro Limited	1800151	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	12,234,215	109,490		0	12,343,705	54,745	12,288,960	4	0	0	491,558	11,852,147
8	101,369	19,930		0	121,299	9,965	111,334	20	0	0	22,267	99,032
10	289,025			694	288,331		288,331	30	0	0	86,499	201,832
12	15,273	50,753		0	66,026	25,377	40,649	100	0	0	40,649	25,377
45	16,333			0	16,333		16,333	45	0	0	7,350	8,983
47	2,049,972	1,049,711		0	3,099,683	524,856	2,574,827	8	0	0	205,986	2,893,697
50	9,436	8,778		0	18,214	4,389	13,825	55	0	0	7,604	10,610
Totals	14,715,623	1,238,662		694	15,953,591	619,332	15,334,259				861,913	15,091,678

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.

Ontario

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Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

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
Orangeville Hydro Limited	1800151	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)* . . . . = + 144,533 **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 . . . . = 144,533 **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 . . . . = 144,533 **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** 144,533

From **N** – ______

Current year deduction **M minus N** . . . . = 144,533 x 7 % = + 10,117 **O**

N + O . . . . = 10,117 ▷ – 10,117 **P**

Enter amount in box 651 *of the CT23*

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.*

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)* . . . . = 134,416 **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
Orangeville Hydro Limited	1800151	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 =

200

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

055 **Do not use this area**

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** 89952 4813 RC0001

Corporation's name

002 Grand Valley Energy Inc.

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . **010** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018)

011 400 C-Line

012 Station A Box 400

City: **015** Orangeville

Province, territory, or state: **016** ON

Country (other than Canada): **017** CA

Postal code/Zip code: **018** L9W 2Z7

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . **020** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028)

021 c/o

022 400 C-Line

023 Station A Box 400

City: **025** Orangeville

Province, territory, or state: **026** ON

Country (other than Canada): **027** CA

Postal code/Zip code: **028** L9W 2Z7

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . **030** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038)

031 400 C-Line

032 Station A Box 400

City: **035** Orangeville

Province,territory, or state: **036** ON

Country (other than Canada): **037** CA

Postal code/Zip code: **038** L9W 2Z7

040 **Type of corporation at the end of the tax year**

1 ☒ Canadian-controlled private corporation (CCPC)

2 ☐ Other private corporation

3 ☐ Public corporation

4 ☐ Corporation controlled by a public corporation

5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ______ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2008-01-01 YYYY MM DD

Tax year-end **061** 2008-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . **065** ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒

Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☒ 2 No ☐

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used . . . . **079** ______

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ______

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091	**092**	**093**	**094**	**095**	**096**
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	**150**	☒	9
Is the corporation an associated CCPC?	**160**	☒	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**	☒	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**	☒	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**	☒	3
Is the corporation claiming any type of losses?	**204**	☒	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	**205**	☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	**206**	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	**207**	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	**208**	☒	8
Does the corporation have any property that is eligible capital property?	**210**	☐	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**	☐	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	**234**	☐	———
Is the corporation claiming a surtax credit?	**237**	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	**238**	☐	38
Is the corporation claiming a Part I tax credit?	**242**	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	**243**	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	**244**	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	**249**	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	**250**	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	**253**	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	**254**	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	**255**	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☒	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes ☐	2 No ☒

What is the corporation's major business activity? **282** ______
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒
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	21,768	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	21,768			
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal		21,768	►	21,768	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")					C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360		
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)					Z

* This amount is equal to 3 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** 21,768 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** 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** *** D / 11,250 = ... E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** 400,000 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				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")				I

Amount I		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		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=		K
Amount I		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		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 ______ 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 / Number of days in the tax year	366 / 366	x	8.5 %	=		V
Amount T		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=		W
Amount T		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=		W1

General tax reduction – Total of amounts U, V, W, and W1 ______ X
Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income 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 . . . . ________

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 = ________

________ ▶ ________

x 26 2 / 3 % = ________ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . ________

Deduct: Corporate surtax from line 600 . . . . ________

Net amount . . . . ________ ▶ ________ 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 . . . . 10,000 x 1 / 3 3,333 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** ______ A

Corporate surtax calculation

Base amount from line A above . . . . ______ 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) . . . . ______ 2

Investment corporation deduction from line 620 below . . . . ______ 3

Federal logging tax credit from line 640 below . . . . ______ 4

Federal qualifying environmental trust tax credit from line 648 below . . . . ______ 5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360 . . . . ______ a

28.00 % of taxed capital gains . . . . ______ b

Part I tax otherwise payable (line A **plus** lines C and D **minus** line F) . . . . ______ c

______ 6

Total of lines 2 to 6 . . . . ______ 7

Net amount (line 1 **minus** line 7) . . . . ______ 8

Corporate surtax*

Line 8 ______ 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 . . . . ______

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . ______

Net amount . . . . ______ ▶ ______ 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) ______ E

Deduct:

Small business deduction from line 430 . . . . ______ 9

Federal tax abatement . . . . **608** ______

Manufacturing and processing profits deduction from Schedule 27 . . . . **616** ______

Investment corporation deduction . . . . **620** ______

Taxed capital gains **624** ______

Additional deduction – credit unions from Schedule 17 . . . . **628** ______

Federal foreign non-business income tax credit from Schedule 21 . . . . **632** ______

Federal foreign business income tax credit from Schedule 21 . . . . **636** ______

Resource deduction from line 438 . . . . ______ 10

General tax reduction for CCPCs from amount M . . . . **638** ______

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 ______ ▶ ______ F

Part I tax payable – Line E **minus** line F . . . . ______ G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable **700**

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

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** 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**

Total credits **890** 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** Oosterhoff (Last name in block letters) **951** John (First name in block letters) **954** President (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009-08-26 Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (519) 928-5652 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 Janet Howard Name in block letters

959 (519) 942-8000 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

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Grand Valley Energy Inc.	89952 4813 RC0001	2008-12-31

Balance sheet information

Assets

Account	Description	GIFI		Current year	Prior year
	Total current assets	1599	+	451,806	
	Total tangible capital assets	2008	+	1,168,040	
	Total accumulated amortization of tangible capital assets	2009	–	822,277	
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+		
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	797,569	

Liabilities

Account	Description	GIFI		Current year	Prior year
	Total current liabilities	3139	+	288,645	
	Total long-term liabilities	3450	+	33,746	
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	322,391	

Shareholder equity

Account	Description	GIFI		Current year	Prior year
	Total shareholder equity (mandatory field)	3620	+	475,178	
	Total liabilities and shareholder equity	3640	=	797,569	

Retained earnings

Account	Description	GIFI		Current year	Prior year
	Retained earnings/deficit – end (mandatory field)	3849	=	38,207	

***** Generic item

Attached Schedule with Total

GIFI code 1060 – Accounts receivable

Title GIFI code 1060 – Accounts receivable

Description	Amount
Accounts receivable	152,960 00
Accrued unbilled revenue	49,591 00
Total	202,551 00

Attached Schedule with Total

GIFI code 2920 – Current portion of long-term liability

Title GIFI code 2920 – Current portion of long-term liability

Description	**Amount**	
Current portion of consumer deposits	3,000	00
Current portion of regulatory liabilities	7,314	00
Total	10,314	00

Attached Schedule with Total

GIFI code 3320 – Other long-term liabilities

Title GIFI code 3320 – Other long-term liabilities

Description	Amount	
Regulatory liabilities	16,758	00
Consumer deposits	16,988	00
Total	33,746	00

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Grand Valley Energy Inc.	89952 4813 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	+	927,107	
	Cost of sales	8518	–	690,812	
	Gross profit/loss	8519	=	236,295	
	Cost of sales	8518	+	690,812	
	Total operating expenses	9367	+	256,736	
	Total expenses (mandatory field)	9368	=	947,548	
	Total revenue (mandatory field)	8299	+	949,269	
	Total expenses (mandatory field)	9368	–	947,548	
	Net non-farming income	9369	=	1,721	
	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	=	1,721	
	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	–		
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,721	

Attached Schedule with Total

GIFI code 9270 – Amount – Other expenses

Title GIFI code 9270 – Amount – Other expenses

Description	Amount
Distribution	32,409 00
Billing and collection	64,628 00
Financial	1,109 00
Total	98,146 00

Canada Revenue Agency　Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Grand Valley Energy Inc.	89952 4813 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 ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes ☐ 2 No ☒

* 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 ☒

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 ☒

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 ☒ 2 No ☐

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes ☐ 2 No ☒

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes ☒ 2 No ☐

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes ☒ 2 No ☐

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes ☐ 2 No ☒

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes ☐ 2 No ☒

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes ☐ 2 No ☐

T2 BAR CODE RETURN

Name: **Grand Valley Energy Inc.**

BN: 89952 4813 RC 0001

Tax Year Start: **2008-01-01** **Taxation Year End:** **2008-12-31**

Notes to follow by fax.

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
Grand Valley Energy Inc.	89952 4813 RC0001	2008-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements				1,721 A
Add:				
Amortization of tangible assets	104	42,794		
Subtotal of additions		42,794	▶	42,794
Other additions:				
Miscellaneous other additions:				
604				
Subtotal of other additions	199	0	▶	0
Total additions	500	42,794	▶	42,794
Deduct:				
Capital cost allowance from Schedule 8	403	22,747		
Subtotal of deductions		22,747	▶	22,747
Other deductions:				
Miscellaneous other deductions:				
704				
Total	394			
Subtotal of other deductions	499	0	▶	0
Total deductions	510	22,747	▶	22,747
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				21,768

* For reference purposes only

T2 SCH 1 E (08)

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
Grand Valley Energy Inc.	89952 4813 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 **400**	Business Number **410**	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD **420**	Taxable dividends paid to connected corporations **430**
1			

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

Total taxable dividends paid in the taxation year to other than connected corporations	**450**	10,000
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	**460**	10,000

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)			10,000
Other dividends paid in the taxation year (total of 510 to 540)			
Total dividends paid in the taxation year	**500**		10,000
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			10,000

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
Grand Valley Energy Inc.	89952 4813 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		21,768
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter as a positive amount)		
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)		
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

Non-capital loss at the end of the previous tax year		44,936	
Deduct: Non-capital loss expired *	100		
Non-capital losses at the beginning of the tax year	102	44,936	
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		44,936
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	21,768	
Amount applied against taxable dividends subject to Part IV tax	135		21,768
Subtotal			23,168
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		23,168

* 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

Capital losses at the end of the previous tax year **200**

Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation **205**

Deduct:

Other adjustments (includes adjustments for an acquisition of control) **250**

Section 80 – Adjustments for forgiven amounts **240**

Add: Subtotal

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

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.

Deduct: Amount applied against the current-year capital gain (see Note 1) **225**

Subtotal

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		**951**	
Second previous tax year		**952**	
Third previous tax year		**953**	

Capital losses – Closing balance **280**

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)

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A				N/A		
2007	10,218	N/A		N/A			10,218
2006	9,620	N/A		N/A			9,620
2005	25,098	N/A		N/A	21,768		3,330
2004		N/A		N/A			
2003		N/A		N/A			
2002		N/A		N/A			
2001		N/A		N/A			*
Total	44,936				21,768		23,168

Farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A				N/A		
2007		N/A		N/A			
2006		N/A		N/A			
2005		N/A		N/A			
2004		N/A		N/A			
2003		N/A		N/A			
2002		N/A		N/A			
2001		N/A		N/A			
2000		N/A		N/A			
		N/A		N/A			
		N/A		N/A			*
Total							

Restricted farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A				N/A	N/A	
2007		N/A		N/A		N/A	
2006		N/A		N/A		N/A	
2005		N/A		N/A		N/A	
2004		N/A		N/A		N/A	
2003		N/A		N/A		N/A	
2002		N/A		N/A		N/A	
2001		N/A		N/A		N/A	
2000		N/A		N/A		N/A	
		N/A		N/A		N/A	
		N/A		N/A		N/A	*
Total						N/A	

* **This balance expires this year and will not be available next year.**

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Grand Valley Energy Inc.	89952 4813 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	Former Elect Distribution Equip	448,965			0		448,965	4	0	0	17,959	431,006
2	8	Equipment	4,012			0		4,012	20	0	0	802	3,210
3	10		1,927			0		1,927	30	0	0	578	1,349
4	12	Computer Software				0			100	0	0		
5	45	Computer Equip	801			0		801	45	0	0	360	441
6	47	Elect Distribution Equip		76,190		0	38,095	38,095	8	0	0	3,048	73,142
		Total	455,705	76,190			38,095	493,800				22,747	509,148

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.

T2 SCH 8 (06)

Canada

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		76,190		
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	+			
	+			
Total additions per books	=	76,190	▶	76,190
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	+			
	+			
Total proceeds per books	=		– ▶	
Depreciation and amortization per accounts – Schedule 1			–	42,794
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	33,396

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		345,763
Opening net book value	–	312,367
Net change per financial statements	=	33,396

If the amounts from the tax return and the financial statements differ, explain why below.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Grand Valley Energy Inc.	89952 4813 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	Country of residence (if other than Canada)	Business Number (Canadian corporation only) (see note 1)	Relationship code (see note 2)	Number of common shares owned	% of common shares owned	Number of preferred shares owned	% of preferred shares owned	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	Grand Valley Services Inc.		86290 6526 RC0001	3					
2.	Township Of East Luther Grand Vall		NR	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

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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 ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Asso-ciation code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	Grand Valley Energy Inc.	89952 4813 RC0001	1	400,000	100.0000	400,000	
2	Grand Valley Services Inc.	86290 6526 RC0001	1	400,000			
3	Township Of East Luther Grand Valley	NR	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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Grand Valley Energy Inc.	89952 4813 RC0001	2008-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Township Of East Luther Grand Valley	NR			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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
Grand Valley Energy Inc.	89952 4813 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		10,000			
Total taxable dividends paid in the tax year	100	10,000			
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		
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.

Canada

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.

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☒ Yes ☐ No

Page 1 of 20

Ministry Use

Corporation's Legal Name *(including punctuation)*
Grand Valley Energy Inc.

Ontario Corporations Tax Account No. (MOF)
1800254

This Return covers the Taxation Year
Start (year month day) 2008-01-01
End (year month day) 2008-12-31

Mailing Address
400 C-Line
Station A Box 400
Orangeville
ON CA L9W 2Z7

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) 2000-07-14

Registered/Head Office Address
400 C-Line
Station A Box 400
Orangeville
ON CA L9W 2Z7

Ontario Corporation No. (MGS) 1429419

Location of Books and Records
400 C-Line
Station A Box 400
Orangeville
ON CA L9W 2Z7

Canada Revenue Agency Business No.
If applicable, enter 89952 4813 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Janet Howard	(519) 942-8000	(519) 941-6061

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*

Ministry Use

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▸ No. of Schedule(s)

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▸ ☒ **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)*
John Oosterhoff

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.

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 ☒ Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 ☐ Other Private

3 ☐ Public

4 ☐ Non-share Capital

5 ☐ Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 ☐ Family Farm corporation s.1(2)

2 ☐ Family Fishing corporation s.1(2)

3 ☐ Mortgage Investment corporation s.47

4 ☐ Credit Union s.51

5 ☐ Bank Mortgage subsidiary s.61(4)

6 ☐ Bank s.1(2)

7 ☐ Loan and Trust corporation s.61(4)

8 ☐ Non-resident corporation s.2(2)(a) or (b)

9 ☐ Non-resident corporation s.2(2)(c)

10 ☐ Mutual Fund corporation s.48

11 ☐ Non-resident owned Investment corporation s.49

12 ☐ Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 ☐ Bare Trustee corporation

15 ☐ Branch of Non-resident s.63(1)

16 ☐ Financial institution prescribed by Regulation only

17 ☐ Investment Dealer

18 ☐ Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 ☒ Hydro successor, municipal electrical utility or subsidiary of either

20 ☐ Producer and seller of steam for uses other than for the generation of electricity

21 ☐ Insurance Exchange s.74.4

22 ☐ Farm Feeder Finance Co-operative corporation

23 ☐ Professional corporation (incorporated professionals only)

☐ This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

☐ Amended Return

☐ Taxation year end change – Canada Revenue Agency approval required

☐ Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

☒ Final taxation year before amalgamation

☐ The corporation has a floating fiscal year end

☐ There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

☐ There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired

year	month	day

☐ The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

☐ First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

☐ Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
☐	☒	Was the corporation inactive throughout the taxation year?
☒	☐	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
☐	☒	the Carry-back of a Loss?
☐	☒	an Overpayment?
☐	☒	a Specified Refundable Tax Credit?
☐	☒	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

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	21,768
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	21,768
Net capital losses From 715 (page 16) ______ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	

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	

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) ______ x 30 100.0000 % Ontario Allocation x 12.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 33 ______ ÷ (Total Days) 73 366 = + 29 ______

From 10 (or 20 if applicable) ______ x 30 100.0000 % Ontario Allocation x 14 % x (Days after Dec. 31, 2003) 34 366 ÷ (Total Days) 73 366 = + 32 ______

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 ______

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) ☐ Yes ☒ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))				50	
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51			
Add: Losses of other years deducted for federal purposes (fed.s.111)	+	52			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	–	53			
	=		▶	54	
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000		

Ontario Business Limit Calculation

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 31 ______ ÷ ** 366 = + 46 ______

400,000 x (Days after Dec. 31, 2003) 34 366 ÷ ** 366 = + 47 ______

Business Limit for Ontario purposes 46 + 47 = 44 500,000 x (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) 48 100.0000 % = 45 500,000

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 ______ (Least of 50 , 54 or 45) = 60 ______

---

* ***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
Grand Valley Energy Inc.	1800254	2008-12-31

DOLLARS ONLY

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] Total Days 366 = + [89] .

8.5 % x [34] Days after Dec. 31, 2003 366 ÷ [73] Total Days 366 = + [90] 8.5000

IDSBC Rate for Taxation Year [89] + [90] - = [78] 8.5000

Claim - - - - - - - - - - - - - - From [60] ______ x From [78] 8.5000 % - - - = [70]

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]

If you are a member of an associated group (X) [81] ☒ (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)
Grand Valley Services Inc.	7151317	2008-12-31	+ 82	
Township Of East Luther Grand Valley		2008-12-31	+ 83	
			+ 84	

Aggregate Taxable Income [80] + [82] + [83] + [84] , etc. - - - - - - - - - - - - - - - - - - - = [85]

Number of Days in Taxation Year

320,000 x [31] Days after Dec. 31, 2002 and before Jan. 1, 2004 ______ ÷ [73] Total Days 366 = + [115]

400,000 x [34] Days after Dec. 31, 2003 366 ÷ [73] Total Days 366 = + [116]

[115] + [116] = 500,000 - - - - - - – [114] 500,000

(If negative, enter nil) - = [86]

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax - - - - - - - - - - 4.6670 % x [38] Days after Dec. 31, 2002 ______ ÷ [73] Total Days 366 = + [97] 4.2500

From [86] ______ x From [97] 4.2500 % - - - - - - - - - = [87]

From [87] ______ x From [60] ______ ÷ From [114] 500,000 = [88]

Surtax Lesser of [70] or [88] - = [100]

**** 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

DOLLARS ONLY

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 .

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 . ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 .

*Ontario Allocation

Lesser of 56 or 121 - + 122 .

120 – 56 + 122 - = 130 .

Taxable Income - + From 10 .

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - – From 56 .

Add: Adjustments for Surtax on Canadian-controlled private corporations - - - - - - - - - - - - + From 122 .

Subtract: Taxable Income 10 ______ 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 .

Claim

Number of Days in Taxation Year

143 . x From 30 100.0000 % x 1.5 % x Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ____ ÷ Total Days: 73 366 = + 154 .

Lesser of 130 or 142 — Ontario Allocation

143 . x From 30 100.0000 % x 2 % x Days after Dec. 31, 2003: 34 366 ÷ Total Days: 73 366 = + 156 .

Lesser of 130 or 142 — Ontario Allocation

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 .

continued on Page 7

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

Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194

Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) - - - - - - - - - - - - - - - + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)

Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* - - + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)

Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) - + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)

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

Applies to employment of eligible apprentices. 202

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

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 - + 240 797,569 •

Total Revenue of the corporation - + 241 949,269 •

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 ☒ (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
Grand Valley Services Inc.	7151317	2008-12-31	+ 243	1 •	+ 244	•
			+ 245	•	+ 246	•
			+ 247	•	+ 248	•

Aggregate Total Assets 240 + 243 + 245 + 247 , etc. - - - - - - - - - - - - - = 249 797,570 •

Aggregate Total Revenue 241 + 244 + 246 + 248 , etc. - = 250 949,269 •

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 • (If negative, enter zero) x From 30 100.0000 % (Ontario Allocation) X 4 % = 276 •

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)* - - - - - - - - - - - - - - - - - – 277 •

Subtract: Income Tax - – From 190 •

Net CMT Payable (If negative, enter Nil on Page 17.) - = 280 •

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 •

Gross CMT Payable - - - - - - - - - - - - - - - - - - + From 276 •

Subtract: Foreign Tax Credit for CMT purposes - - - - - - - - - - – From 277 •

If 276 – 277 is negative, enter NIL in 290 = • ▸ – 290 •

Income Tax eligible for CMT Credit - = 300 •

B. Income Tax (after deduction of specified credits) - + From 230 •

Subtract: CMT credit used to reduce income taxes - – 310 •

Income Tax - = 320 •

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
Grand Valley Energy Inc.	1800254	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	100 •
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	38,207 •
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	436,871 •
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	19,988 •
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	•
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	163,385 •
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	•
Subtotal	=	370	658,551 •
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	658,551 •
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	658,551 •

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	•
Mortgages due from other corporations	+	403	•
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	•
Loans and advances to unrelated corporations	+	405	•
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	•
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	•
Total Eligible Investments	=	410	•

continued on Page 10

Total Assets (Int.B. 3015R)

DOLLARS ONLY

Total Assets per balance sheet	+	420	797,569 •
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	797,569 •
Amounts in 360 and 361 (if deducted from assets)	+	440	•
Subtract: Amounts in 371 , 372 and 381	–	441	•
Subtract: Appraisal surplus if booked	–	442	•
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	•
Total Assets	=	450	797,569 •

Investment Allowance (410 ÷ 450) x 390 **Not to exceed** 410	=	460	•
Taxable Capital 390 – 460	=	470	658,551 •

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	949,269 •
Total Assets (as adjusted)	From 430	797,569 •

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

		Days after Dec. 31, 2004 and before Jan. 1, 2006			Total Days			
7,500,000	x	36		÷ 73	366	= +	501	•
		Days after Dec. 31, 2005 and before Jan. 1, 2007			Total Days			
10,000,000	x	37		÷ 73	366	= +	502	•
		Days after Dec. 31, 2006 and before Jan. 1, 2008			Total Days			
12,500,000	x	38		÷ 73	366	= +	504	•
		Days after Dec. 31, 2007			Total Days			
15,000,000	x	39	366	÷ 73	366	= +	505	15,000,000 •

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 15,000,000 •

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

		Days before Jan. 1, 2007			Total Days			
0.3 %	x	556		÷ 73	366	= +	511	%
		Days after Dec. 31, 2006 and before Jan. 1, 2009			Total Days			
0.225 %	x	557	366	÷ 73	366	= +	512	0.2250 %

Capital Tax Rate 511 + 512 = 516 0.2250 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

\+ From 470 ______ •

– From 503 ______ •

= 471 ______ • x From 30 100.0000 % Ontario Allocation x From 516 0.2250 % Capital Tax Rate x Days in taxation year 555 366 / 366 (366 if leap year) = + 523 ______ •

If floating taxation year, refer to Guide.

Transfer to 543 *on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ 509 (X if applicable) All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. ☒ 524 (X if applicable) One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation

Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - + From 470 658,551

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
Grand Valley Services Inc.	7151317	2008-12-31	+ 531	
Township Of East Luther Grand Valley		2008-12-31	+ 532	
			+ 533	

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - = 540 658,551

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 470 658,551 ÷ From 540 658,551 x From 503 15,000,000 = 541 15,000,000

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

☐ 591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.*
Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+ From 470 658,551
– 542 15,000,000
= 471 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) x 555 366 (Days in taxation year) = + 523 (**Total Capital Tax for the taxation year**)

* 366 (366 if leap year)

Transfer to 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) - - - - - - - = + 561

– Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - – From 995

= 562

Capital Tax - - - - - - - - 562 x 555 366 (Days in taxation year) - - - - - = 563 (**Total Capital Tax for the taxation year**)

* 366 (366 if leap 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

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - - - - - - - - – 546

Capital Tax 543 – 546 *(amount cannot be negative)* - - - - - - - - - - - - - - - - - = 550

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ______ x 567 ______% x From 30 100.0000 % x 555 366 / * 366 (366 if leap year) - - - - = + 569 ______
Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 — Capital Tax Rate (1) *(Refer to Guide)* — Ontario Allocation — Days in taxation year

570 ______ x 571 ______% x From 30 100.0000 % x 555 366 / * 366 (366 if leap year) - - - - = + 574 ______
Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount — Capital Tax Rate (2) *(Refer to Guide)* — Ontario Allocation — Days in taxation year

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	21,768 *Transfer to Page 15*

Add:

Federal capital cost allowance	+	601	22,747
Federal cumulative eligible capital deduction	+	602	
Ontario taxable capital gain	+	603	
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 [Days after Dec. 31, 2002 and before Jan. 1, 2004] 33 ______ ÷ 73 [Total Days] 366 =+ 633 ______

612 ______ x 5 / 14 x [Days after Dec. 31, 2003] 34 366 ÷ 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	=		22,747 ▶ 640 22,747 *Transfer to Page 15*

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+	650	22,747
Ontario cumulative eligible capital deduction	+	651	
Federal taxable capital gain	+	652	
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	22,747 *Transfer to Page 15*

continued on Page 15

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Grand Valley Energy Inc.	1800254	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 21,768 •

Total of Additions on page 14 - From = 640 22,747 •

Sub Total of deductions on page 14 - From = 681 22,747 •

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 = 22,747 • ▶ 680 22,747 •

Net income (loss) for Ontario Purposes 600 + 640 – 680 - = 690 21,768 •

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) 44,936	710 (2)	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) 21,768	715 (2) (4)	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 21,768	717	727	737	747	757
Balance at End of Year		709 (8) 23,168	719	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	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 3,330	833	843	856	876
807 2nd preceding taxation year 2006-12-31	824 9,620	834	844	857	877
808 1st preceding taxation year 2007-12-31	825 10,218	835	845	858	878
809 Current taxation year 2008-12-31	826	836	846	859	879
Total	829 23,168	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.

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	•
Corporate Minimum Tax	+ From	280	•
Capital Tax	+ From	550	•
Premium Tax	+ From	590	•
Total Tax Payable	=	950	•
Subtract: Payments	–	960	•
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	•
If payment due	Enclosed *	990	•
If overpayment: Refund *(Refer to Guide)*	=	975	•
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)*: John Oosterhoff

Title: President

Full Residence Address:

Signature:

Date: 2009-08-26

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	
NBV	-345,763	00
UCC	509,148	00
Total	163,385	00

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Grand Valley Energy Inc.	1800254	2008-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)				±	2100	1,721

Subtract (to the extent reflected in net income/loss):

Provision for recovery of income taxes / benefit of current income taxes	+	2101				
Provision for deferred income taxes (credits) / benefit of future income taxes	+	2102				
Equity income from corporations	+	2103				
Share of partnership(s)/joint venture(s) income	+	2104				
Dividends received/receivable deductible under fed.s.112	+	2105				
Dividends received/receivable deductible under fed.s.113	+	2106				
Dividends received/receivable deductible under fed.s.83(2)	+	2107				
Dividends received/receivable deductible under fed.s.138(6)	+	2108				
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) ______ x 3	+	2109				
Subtotal	=			▶ –	2110	

Add (to extent reflected in net income/loss):

Provision for current taxes / cost of current income taxes	+	2111				
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	=			▶ +	2116	

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property, occuring before March 22, 2007, for current/prior years

** Fed.s.85	+	2117		or –	2118			
** Fed.s.85.1	+	2119		or –	2120			
** Fed.s.97	+	2121		or –	2122			
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+	2123		or –	2124			
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/ prior years	+	2125		or –	2126			
** Amounts relating to s.57.10 election/ regulations for replacement re fed.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			
Subtotal (Additions)	=		▶			+	2129	
Subtotal (Subtractions)				=		▶ –	2130	
** Other adjustments						±	2131	

Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131				=	2132	1,721
** 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	1,721
Deduct: * CMT losses: pre-1994 Loss	+ From	2210				
* CMT losses: other eligible losses	+	2211	1,721			
	=		1,721	▶ –	2135	1,721

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base	=	2136	

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Grand Valley Energy Inc.	1800254	2008-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)			+ 2201	37,937
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	37,937
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	1,721		
Losses expired during the year	+ 2212			
Subtotal	=	1,721	– 2213	1,721
Balances at End of Year NOTE (5) 2209 – 2213			= 2214	36,216

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	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 16,124	2287
2248	1st preceding taxation year 2007-12-31	2268 20,092	2288
2249	Current taxation year 2008-12-31	2269	2289
Totals		2270 36,216	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214 .

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOR)	Taxation Year End
Grand Valley Energy Inc.	1800254	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	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
Grand Valley Energy Inc.	1800254	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						
9th Prior Year						
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	17,845		1,721		16,124
1st Prior Year	2007-12-31	20,092				20,092
	Total	37,937		1,721		36,216

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
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
Grand Valley Energy Inc.	1800254	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**
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
Grand Valley Energy Inc.	1800254	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						
9th Prior Year						
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
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
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						

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Grand Valley Energy Inc.	1800254	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 consumer deposits	+ 3,000
Consumer deposits	+ 16,988
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
Total *Transfer to* 353 *of the CT23*	= 19,988

Non-Capital Loss Continuity Workchart – Ontario

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Grand Valley Energy Inc.	1800254	2008-12-31

Non-capital losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2007	10,218	N/A		N/A		10,218
2006	9,620	N/A		N/A		9,620
2005	25,098	N/A		N/A	21,768	3,330
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		*
Total	44,936				21,768	23,168

Farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2007		N/A		N/A		
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
		N/A		N/A		
		N/A		N/A		*
Total						

Restricted farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2007		N/A		N/A		
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
		N/A		N/A		
		N/A		N/A		*
Total						

* **This balance expires this year and will not be available next year.**

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Grand Valley Energy Inc.	1800254	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	448,965			0	448,965		448,965	4	0	0	17,959	431,006
8	4,012			0	4,012		4,012	20	0	0	802	3,210
10	1,927			0	1,927		1,927	30	0	0	578	1,349
12				0				100	0	0		
45	801			0	801		801	45	0	0	360	441
47		76,190		0	76,190	38,095	38,095	8	0	0	3,048	73,142
Totals	455,705	76,190			531,895	38,095	493,800					509,148
											22,747	
								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.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of the OHL electrical system. This includes both direct labor costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering and Stores. Commencing in 2009 OHL has changed our capitalization policy by excluding the engineering department expenses in the overhead rate applied to direct labour. In 2009, the Engineering Department is expensed to account 5085. OHL's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions).

OHL's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with OHL's capital project work, so that where maintenance programs have identified matters the correction of which require capital investments, OHL may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the OHL distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted load break switch maintenance and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. OHL constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by OHL for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Network Control Operations:

In 2010, OHL is working toward a Supervisory Control and Data Acquisition ("SCADA") system. Network operating costs will be contracted out in 2010 and charged to account 5085.

Metering:

OHL contracts out most of the work related to the metering department. This department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

Substation Services:

Substation services activities address the maintenance of all equipment at OHL’s 5 substations. This includes both labor costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, OHL’s substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of OHL’s planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

In 2010 the Engineering department will be responsible for keeping asset related data up to date on a proposed electronic Geographic Information System (“GIS”) and Supervisory Control and Data Acquisition (SCADA). The GIS system will be used for asset management activities, troubleshooting system problems in the control room, delivering underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. Engineering will also implement and manage the proposed SCADA system. Engineering also delivers drafting services to the design technicians for capital projects and provides distribution system asset information to many departments within OHL. Prior to 2009 Engineering costs were allocated to operations, maintenance, capital, and Third Party receivable accounts based on direct labor costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end. This department will now track their time as direct labour charged to account 5085 and to specific capital projects.

STORES/WAREHOUSE

Stores area is shared duties of other departments and is accountable for managing the procurement, control, and movement of materials within OHL's service centre. This would include monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

GARAGE/TRANSPORTATION FLEET

This area is shared duties of other departments and assists with the maintenance and control of approximately 9 fleet vehicles. Its objectives include keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard hourly cost/hr is set for all vehicles within the fleet. Costs are adjusted to actual at year end.

LABOUR BURDEN/SAFETY AND HEALTH

This department collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments, capital and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

In addition, the cost of Safety and Health is included in this department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. OHL is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. OHL was recently award the Bronze Medal for safety by E&USA in the quest for zero lost time accidents.

CUSTOMER SERVICE

The Customer Service group is responsible for the customer care activities for the approximately 11,000 customers in OHL's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. OHL aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are collected in accounts 5305 to 5515.

Meter Reading:

Meter reading services are contracted out to a non-affiliated third party under a service contract agreement. On average the contractor reads 11,000 electric service meters per month. The meter contract is updated every year after the completion of a competitive bid process. The initial contract was a three year term with a provision for a further two year extension upon mutual agreement. In addition, the agreement was recently extended for an additional two year period through 2010 at current rates plus an adjustment for escalating gasoline prices.

Billing:

OHL performs monthly billing and issues 130,000 invoices annually to customers. On average this total includes 1300 final bills for customers moving within or outside of OHL's service territory. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes; EBT and retailer settlement functions for 2,000 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. OHL offers customers a number of billing and payment options including an equal payment plan and a preauthorized payment plan.

Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. Credit risk is a concern for OHL with 2010 credit loss forecast at $20,000. In an effort to minimize credit losses, OHL enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency after collection methods are exhausted. Commencing October, 2007 OHL purchased credit insurance for general service customers to further reduce our risk.

OHL is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. OHL maintains a presence in the communities it serves, where OHL staff is available to answer customer questions in a friendly environment.

Since LDCs are the “face-to-the-customer” for the electricity industry, OHL has an important role to play in educating the public about electricity safety and energy conservation. OHL continues to participate with the OPA in administering programs directed at Energy Conservation. OHL is very active in the community promoting conservation initiatives, attending a number of community events each year, distributing compact florescent light bulbs and energy conservation handbooks.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within OHL, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- Finance and Regulatory Services (5610);
- Administrative Services (5615);

Executive Salaries and Expenses: 5605

The President & the Board of Directors are responsible for all aspects of the OHL. In 2009, also included in this category is the Vice President Administration. This position also oversees the IT-related issues, meter reading, billing and collecting departments and a portion of the salary is expensed to 5305. Expenses include salaries and all related expenses for all employees within the above noted functional areas as well as payroll.

Management Salaries and Expenses: 5610

Financial Services:

The Finance department is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing OHL. Expenses include salaries and all related expenses associated with the Manager of Finance.

Administrative Services: 5615

This department assists the finance department with regulatory accounting and services, accounts payable and accounts receivable. Regulatory reporting includes development and preparation of rate filings, performance reporting, and compliance. Expenses include salary and related costs associated with the Finance Assistant, Regulatory Assistant and Accounts Payable Clerk.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants. The Information Technology consultant also included is responsible for the development, operation, maintenance and security of all business system applications utilized by the utility in its operations under direction of the VP Administration.

Employee Post-Retirement Benefits: 5645

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible OHL employees in accordance with company policy and as provided in the collective bargaining agreement between OHL and its union. The annual expense and liability are determined in accordance with Section 3461 of the CICA Handbook and supported by an actuarial valuation that is completed every three years.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category. Expenses under Electrical Safety Authority (“ESA”) fees include all annual charges from the ESA.

Miscellaneous General Expense: 5665

Bank Service Charges, memberships and other miscellaneous costs are included in this account. OHL is a member of the Electrical Distributor Association and the Cornerstone Hydro Electric Concepts (CHEC). CHEC has a membership of 12 small LDCs. Through our association with the CHEC group we have worked together to reduce costs. We have worked together on common Conditions of Service, Economic Evaluation process, Smart meter procurement with Utili-assist, RFP for Collection Agency services and Audit services, CDM programs, IESO and settlement issues, joint training sessions and International Reporting Financial Standards.

OM&A Cost Table

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Actual	Variance from 2007 Actual	2009 Bridge	Variance from 2008 Actual	2010 Test	Variance from 2009 Bridge
Operations											
5005-Operation Supervision and Engineering	0	0	0	0	0	0	0	0	0	0	0
5010-Load Dispatching	0	0	0	0	0	0	0	0	0	0	0
5012-Station Buildings and Fixtures Expense	0	0	0	0	0	0	0	0	0	0	0
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and E	0	0	0	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	296	659	363	861	202	171	(690)	1,028	857	1,013	(15)
5017-Distribution Station Equipment - Operation Supplies and Ex	20,504	47,344	26,840	30,842	(16,502)	48,558	17,716	64,698	16,140	66,355	1,657
5020-Overhead Distribution Lines and Feeders - Operation Labou	9,669	2,078	(7,592)	3,785	1,707	3,242	(543)	3,652	411	3,758	105
5025-Overhead Distribution Lines & Feeders - Operation Supplies	823	174	(649)	0	(174)	1,607	1,607	1,080	(527)	1,080	0
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	99	0	(99)	769	769	1,108	339	3,422	2,314	3,558	136
5040-Underground Distribution Lines and Feeders - Operation La	3,011	1,241	(1,770)	585	(656)	1,119	534	475	(645)	1,492	1,018
5045-Underground Distribution Lines & Feeders - Operation Sup	411	548	137	23	(525)	242	219	180	(62)	270	90
5050-Underground Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	0	878	878	378	(500)	986	608	676	(310)	694	18
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0	0	0	0
5065-Meter Expense	66,275	74,472	8,196	111,882	37,411	86,151	(25,732)	90,292	4,141	103,931	13,640
5070-Customer Premises - Operation Labour	20,631	46,539	25,907	62,348	15,809	49,285	(13,063)	39,742	(9,543)	44,701	4,960
5075-Customer Premises - Materials and Expenses	34,185	29,011	(5,175)	17,998	(11,013)	14,660	(3,337)	18,098	3,438	19,505	1,407
5085-Miscellaneous Distribution Expense	37,357	39,128	1,770	34,186	(4,941)	124,310	90,123	89,723	(34,587)	156,263	66,540
5090-Underground Distribution Lines & Feeders-Rental Paid	0	0	0	0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	5,364	0	(5,364)	0	0	0	0	0	0	0	0
5096-Other Rent	1,107	6,736	5,629	7,489	752	7,482	(7)	6,325	(1,157)	6,325	0
Sub-Total	**199,733**	**248,806**	**49,073**	**271,145**	**22,339**	**338,920**	**67,775**	**319,390**	**(19,530)**	**408,946**	**89,556**

Maintenance

5105-Maintenance Supervision and Engineering	52,678	53,982	1,304	66,908	12,926	90,555	23,647	122,585	32,030	128,570	5,986
5110-Maintenance of Buildings and Fixtures - Distribution Statio	0	0	0	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	9,133	-36,345	(45,479)	1,733	38,078	18,743	17,010	11,091	(7,652)	11,345	255
5120-Maintenance of Poles, Towers and Fixtures	16,196	44,245	28,049	36,482	(7,763)	27,160	(9,322)	19,983	(7,177)	23,374	3,391
5125-Maintenance of Overhead Conductors and Devices	66,434	75,188	8,754	79,905	4,717	83,883	3,978	63,242	(20,641)	69,136	5,894
5130-Maintenance of Overhead Services	23,395	25,292	1,896	27,582	2,291	26,555	(1,027)	12,571	(13,984)	19,169	6,598
5135-Overhead Distribution Lines and Feeders - Right of Way	55,495	67,756	12,261	51,671	(16,085)	115,788	64,118	98,825	(16,963)	104,245	5,420
5145-Maintenance of Underground Conduit	45	46	0	798	752	0	(798)	0	0	0	0
5150-Maintenance of Underground Conductors and Devices	30,832	17,290	(13,542)	21,924	4,634	8,329	(13,595)	7,681	(648)	10,732	3,052
5155-Maintenance of Underground Services	53,447	49,114	(4,334)	84,201	35,087	68,555	(15,646)	75,872	7,317	80,437	4,564
5160-Maintenance of Line Transformers	58,098	29,632	(28,467)	70,325	40,693	17,313	(53,012)	35,826	18,514	45,413	9,587
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour	0	1,513	1,513	3,229	1,716	894	(2,336)	0	(894)	0	0
5172-Sentinel Lights- Materials and Expenses	0	928	928	723	(205)	225	(498)	0	(225)	0	0
5175-Maintenance of Meters	13,040	10,727	(2,313)	0	(10,727)	0	0	0	0	0	0
5178-Customer Installations Expenses - Leased Property	0	0	0	0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	**378,794**	**339,366**	**(39,428)**	**445,480**	**106,114**	**457,999**	**12,519**	**447,677**	**(10,322)**	**492,423**	**44,746**

Billing and Collections

5305-Supervision	25,760	28,970	3,211	29,768	798	30,942	1,174	24,493	(6,449)	26,093	1,599
5310-Meter Reading Expense	110,880	92,682	(18,198)	98,765	6,082	97,875	(890)	112,253	14,378	114,976	2,724
5315-Customer Billing	204,528	186,772	(17,756)	192,648	5,876	210,800	18,152	209,046	(1,754)	238,412	29,366
5320-Collecting	105,833	122,015	16,183	128,939	6,924	137,665	8,726	142,867	5,202	160,472	17,605
5325-Collecting- Cash Over and Short	39	178	139	-123	(301)	-485	(362)	0	485	0	0
5330-Collection Charges	(0)	0	0	0	0	0	0	0	0	0	0
5335-Bad Debt Expense	23,135	46,042	22,907	33,590	(12,453)	24,916	(8,674)	20,000	(4,916)	20,000	0
5340-Miscellaneous Customer Accounts Expenses	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	**470,174**	**476,660**	**6,486**	**483,587**	**6,927**	**501,713**	**18,126**	**508,659**	**6,946**	**559,953**	**51,294**

Community Relations

5405-Supervision	0	0	0	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	24,957	48,971	24,014	23,610	(25,361)	23,856	247	12,584	(11,273)	28,862	16,278
5415-Energy Conservation	0	102,620	102,620	144,721	42,101	18,695	(126,026)	0	(18,695)	0	0
5420-Community Safety Program	0	0	0	0	0	0	0	0	0	0	0
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	**24,957**	**151,591**	**126,634**	**168,331**	**16,740**	**42,551**	**(125,780)**	**12,584**	**(29,967)**	**28,862**	**16,278**

Administrative and General Expenses

5605-Executive Salaries and Expenses	194,039	211,213	17,174	217,188	5,975	250,260	33,072	357,898	107,638	386,005	28,107
5610-Management Salaries and Expenses	159,457	144,703	(14,754)	157,627	12,924	153,939	(3,688)	129,183	(24,756)	132,149	2,966
5615-General Administrative Salaries and Expenses	64,303	55,885	(8,418)	101,281	45,396	134,014	32,732	182,252	48,238	270,196	87,944
5620-Office Supplies and Expenses	79,778	60,361	(19,417)	43,213	(17,149)	46,635	3,422	47,081	446	53,799	6,718
5625-Adminsitrative Expense Transferred-Credit	0	0	0	0	0	0	0	0	0	0	0
5630-Outside Services Employed	84,024	194,404	110,380	183,497	(10,907)	227,331	43,834	97,639	(129,692)	123,329	25,690
5635-Property Insurance	10,934	6,600	(4,334)	9,762	3,162	21,046	11,284	22,342	1,296	26,412	4,070
5640-Injuries and Damages	40,368	16,079	(24,289)	21,508	5,429	22,654	1,146	19,856	(2,798)	20,253	397
5645-Employee Pensions and Benefits	25,510	30,899	5,389	31,638	739	43,881	12,243	38,343	(5,538)	37,330	(1,013)
5650-Franchise Requirements	0	0	0	0	0	0	0	0	0	0	0
5655-Regulatory Expenses	41,412	8,456	(32,956)	39,549	31,093	44,408	4,859	40,807	(3,601)	77,072	36,265
5660-General Advertising Expenses	0	911	911	1,090	179	0	(1,090)	0	0	0	0
5665-Miscellaneous General Expenses	371,090	50,480	(320,609)	58,188	7,708	43,605	(14,583)	70,226	26,621	74,656	4,430
5670-Rent	4,200	2,450	(1,750)	0	(2,450)	0	0	0	0	0	0
5675-Maintenance of General Plant	60,419	66,178	5,759	72,050	5,872	79,173	7,123	75,259	(3,914)	77,632	2,373
5680-Electrical Safety Authority Fees	0	1,609	1,609	0	(1,609)	0	0	0	0	0	0
5685-Independent Market Operator Fees and Penalties	0	0	0	0	0	0	0	0	0	0	0
Sub-Total	**1,135,534**	**850,229**	**(285,304)**	**936,592**	**86,362**	**1,066,947**	**130,355**	**1,080,885**	**13,938**	**1,278,832**	**197,946**
Total Operating, Maintenance and Administration Expenses	**2,209,192**	**2,066,653**	**(142,539)**	**2,305,135**	**238,482**	**2,408,130**	**102,996**	**2,369,195**	**(38,936)**	**2,769,015**	**399,821**

VARIANCE ANALYSIS ON OM&A COSTS:

OHL has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year including the variances year over year in Exhibit 4, Tab 2, Schedule 2, above. Before moving to a variance analysis for each account that exceeds the materiality threshold, a summary of total OM&A expenses (excluding depreciation) is presented below along with an analysis of the total movement from 2006 Actual to 2010 Test Year.

Table 4

Cost Driver Table

OM & A Cost Drivers	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Opening Balance	2,209,192	2,066,653	2,305,135	2,408,130	2,369,195
OEB Reclassification	(304,340)	91,100	(126,000)	(18,000)	0
Payroll Changes	(136,000)	(23,000)	143,000	(13,000)	200,000
Change in Cost of Material/Supplies	16,000	24,000	(18,000)	25,000	6,000
Change in Cost of Contractors	168,000	82,000	45,000	(92,000)	140,000
Inflation	113,801	64,382	58,996	59,064	53,821
Closing Balance	2,066,653	2,305,135	2,408,130	2,369,195	2,769,015

2006 Cost Drivers

a) OEB reclassification ($304,340) –

   i. LV charges of ($331k) are reclassified to Cost of Power from account 5665.

   ii. OHL OEB cost assessment from Mar/05-Mar/06 was reclassified to regulatory account 1508 from account 5655 resulting in a total variance of ($29k) to the 2006 EDR in account 5655.

iii. OHL is showing increased costs in account 5415 for CDM educational activities that were funded through 3rd tranche distribution revenue costing $103k. The offsetting revenue is recorded within the Distribution Revenue.

iv. 2005 and 2006 Meter exit rebates ($48k) from Hydro One were received and posted to account 5114.

b) Payroll Changes ($136,000) –

i. The Manager of Grand Valley retired in January 1, 2006 ($78k),

ii. Grand Valley did not have a Manager and it was far too costly to hire the expertise. Grand Valley and Orangeville were also in the process of amalgamation talks so in June 2006, OHL was performing managerial, billing and collecting services for Grand Valley Energy ($58).

c) Change in cost of materials/supplies $16,000 –

i. In 2006, in account 5120 material amounting to $16k was charged to this account and should have been capitalized.

d) Change in cost of contractors $168,000 –

i. Grand Valley required additional assistance due to the retirement of the manager. For ½ of the year, a consultant was contracted amounting to an additional $15k from prior years providing financial and regulatory matters. The Grand Valley Board of Directors decided that Orangeville could provide the service due to the billing system Grand Valley used could not perform retail billing and other settlement issues. For the other ½ of the year Orangeville Hydro provided managerial services along with billing and collecting to Grand Valley amounting to 44k recorded in 5630, 16k recorded in 5315 and 8k recorded in 5320.

ii. An increase resulted in 5630 for audit fees amounting to 14k.

iii. A bankruptcy occurred in the general service class 38k in account 5335

iv. In 2006 in account 5410, we hired a consultant to conduct sessions in the schools as part of our safety in the schools program amounting to 9k.

v. OHL contracted Hydro One to do the load profile for our cost allocation model, $10k in account 5630.

vi. OHL contracted consultant to review and make recommendations regarding opening a services company amounting to $11k and the expense was recorded in 5630.

vii. OHL participated in a customer survey in conjunction with the cost allocation filing to gain information for the appliance survey required for the Hydro One load data information. The amount of $3k was charged to 5410.

e) Inflation $113,801 –

Inflation for 2005 and 2006 combined is 5.2%.

2007 Cost Drivers

OEB reclassification $91,100 –

i. OHL's OEB cost assessment from Mar/05-Mar/06 that was recorded in 2006 caused a $33k variance. There was no reclassification of the OEB Cost Assessments in 2007.

ii. Changes in the CDM account 5415 caused a variance of $42k because OHL spending of the 3rd tranche covers a period of three years. The offsetting revenue was recorded with Distribution Revenue.

iii. The change in Meter Exit rebates for $16k includes the 2006 meter rebate received in 2007 for (14k) recorded in 5017 and the meter rebate for 2007 received in 2007 ($18k) recorded in 5114 and the previous' year rebates of 48k. These entries caused a total variance of $(16k) in account 5017 and 38k in account 5114.

c) Payroll Changes ($23,000) –

- i. A promotion to a newly created position of Finance Assistant resulted in $17k,
- ii. A Line apprentice commenced employment in November and resulted in an increase of $4k.
- iii. The further change in payroll shifting costs of ($44k) resulted from the managerial services provided to Grand Valley for a full year that affected accounts 5105, 5315, 5320, 5605, 5610, 5615 and 5630.

d) Change in cost of materials/supplies $24,000 –

- i. OHL wrote off obsolete inventory relating to account 5155 amounting to $9k .
- ii. The Manager of Administration and Customer Service attended a business course for further development $11k and the Manager of Finance attended an additional course amounting to $4k for regulatory and cost of service application education both relating to account 5610.

e) Change in cost of contractors $82,000 –

- i. OHL contracted a Human Resources company to conduct and employee survey and table the results $15k that increased account 5630.
- ii. We required additional work performed by our meter contractor for a back log for 3 phase meter work that increased our usual contract by $22k in account 5065.
- iii. OHL's CIS vendor sold the business to Harris and there were additional charges for deregulation support that resulted in an increase of $17k in accounts 5315 and 5320.
- iv. OHL had more PCB testing completed that led to an additional increase in account 5016 for contractor costs of $8k.
- v. Grand Valley services contract for the full year increased contracting costs a further 53k in account 5315, 5320 and 5630.
- vi. There was a decrease in account 5335 for bad debts over last year of ($12k)

f) Inflation $64,382 –

Inflation is 3.1% due to increasing contractor contract costs and payroll.

2008 Cost Drivers

a) OEB reclassification $(126,000) –

  i. OHL completed the third tranche CDM program in 2008. The variance in account 5415 resulted as the spending was less than the prior year.

b) Payroll Changes $143,000 –

  i. OHL hired an Administrative Assistant to handle CDM with the OPA and perform administrative duties resulting increased costs of $39k with a percentage of the salary and benefits being allocated to 4380 for OPA expenses.

  ii. OHL hired an apprentice lineman late 2007 and it has added an additional $20k to the operating expenses.

  iii. There were 2 retirements, a line technician and a customer service representative, resulting in vacation payouts and retirement benefits of $30k.

  iv. OHL hired a Cashier in mid June to cover while the original cashier was trained and moved to the position of Customer Service Representative amounting to $12k

  v. A new member was added to our Board of Directors and in the same year research was completed on compensation for LDC Board of Directors that resulted in a 27k increase.

  vi. The Engineering Technician left the company at the end of the year and there was a vacation payout of $7k and an Engineering Cooperative student hired for an additional 8k.

c) Change in cost of materials/supplies ($18,000) –

  i. EDA and CHEC membership decreased by (12k) in 2008.

ii. We changed banks that reduced the service charge costs and received a signing bonus totalling (6k)

d) Change in cost of contractors $45,000 –

i) OHL saw an decrease of ($8k) in account 5335 for bad debts

ii) OHL employed a consultant to perform an evaluation of the utility at a cost of 18k in account 5630.

iii) OHL also updated our strategic plan and employed a consultant at a cost of $10k in account 5630.

iv) OHL incurred additional legal costs in account 5630 amounting to $11k regarding implementation of the strategic plan and certain governance matters.

v) With the recent bankruptcy of one of our larger general service customers, OHL felt it prudent to purchase credit insurance on general service accounts amounting to $14k recorded in account 5635. The insurance covers general service accounts leaving a bad debt of over $1,000.

e) Inflation $58,996 –

Inflation is 2.6% due to increasing contractor contract costs and payroll.

2009 Cost Drivers

a) Payroll Changes ($13,000) –

i. We did not fill the position of the Line Technician position amounting to ($78k).

ii. OHL will incur a shift of payroll costs due to the amalgamation of Grand Valley and Orangeville totalling $117k to 5105, 5315, 5320, 5605, 5610 and 5615. Management services and billing and collecting staff will no longer be providing services to Grand Valley Energy.

iii. OHL is implementing a new CIS system in 2009 and have budgeted for additional overtime of $10k in account 5315.

iv. OHL will not be filling the vacancy of the engineering technician until September in account 5085 and 2009 the vacancy caused a reduction in payroll of ($62k).

v. OHL hired a P. Eng recent grad to fill in for the summer until the incumbent engineering tech begins in September $5k recorded in account 5085.

b) Change in cost of material/supplies $25,000 –

i. OHL has experienced a $25k increase in our membership dues for EDA 8k and CHEC $17k in account 5665. The EDA increase is due to the increase in our number of customers. The CHEC increase is the movement towards having a staff member to assist each of the members where needed.

c) Change in cost of contractors ($92,000) –

i. OHL hired a consultant to develop an asset management plan 41k in account 5085.

ii. In order to meet the DSC and ESA requirements OHL has hired a contractor 8k to ensure that the distribution stations, account 5017 needs are met in keeping them in top working order.

iii. The management, billing and collecting service contract of ($136,000) will no longer be required due to the amalgamation of Orangeville and Grand Valley. The change affects accounts 5315 for ($31k), 5320 for ($16k) and 5630 for ($89k).

iv. OHL decreased the budget for bad debts due to the implementation of the credit insurance for the general service customers. We feel a budget of $20k should cover the residential customers in this economic climate. Therefore, the reduction in account 5335 of (5k).

d) Inflation $59,064 –

e) Results in an increase of 2.5% due to increased contractor costs and from payroll costs.

2010 Cost Drivers

a) Payroll Changes $200,000 –

  i. OHL plans to hire a regulatory analyst, to assist with the increasing demands and regulatory interpretations and requirements of the OEB reporting for projects such as rate filings, cost allocations, regulatory accounting, economic evaluations, the regulatory agencies monthly, quarterly and annual filings, and distributed generation settlements for an estimated cost of $82k in account 5615.

  ii. OHL plans to hire a Junior Engineer $76k to assist with the operation of SCADA and GIS, and IT related functions.

  iii. In 2009 there will be an additional 42k recorded in account 5085 due to a full year of payroll for the engineering technician.

b) Change in cost of service $6,000 –

  i. The Vice-President of Administration will be taking additional courses to further her development $6k increasing costs in account 5605.

c) Change in cost of contractors $140,000 –

  i. The new CIS operational costs recorded in accounts 5065, 5310, 5315 and 5320 will increase by $20k because the system will be hosted and maintained by an outside source dealing with all upgrades backup, networking making the costs in the long run less expensive.

  ii. OHL is planning for a new CIS module for the settlement process of the MicroFIT program amounting to $60k.

  iii. OHL will be incurring increased costs of 35k in account 5655 due to the cost of service application. We have budgeted $140 including cost awards and outside assistance.

iv. OHL will be incurring increased costs of 25k in account 5665 due to the International Financial Reporting Standards. This includes assistance through the phases to be prepared for conversion along with additional audit costs. We have budgeted 100k for the total project.

d) Inflation $53,821 –

Inflation is 2.3% due to increasing contractor contract costs and payroll.

Variance Analysis:

As mentioned above, the variance that triggers the required analysis is $50,000 according to the Filing Requirements (50,000 for distributors with a distribution revenue requirement less than or equal to $10 million). OHL has explained any variances that exceed $25,000 in order to produce a better analysis. OHL has reviewed the variance of each OEB USoA account to determine where explanations are necessary. The variances have been highlighted in Exhibit 4, Tab 2, Schedule 2 and an explanation of each variance is presented in the following section. The Table 5 below highlights the variance from the 2006 Actuals to the 2010 Test Year and the 2008 Actual to the 2010 Test year. Explanations of these variances are included in the synopsis below:

Table 5 OM&A Cost Table

Expense Description	2006 Actual	2010 Test	Variance from 2006 Actuals	2008 Actual	2010 Test	Variance from 2008 Actuals
Operations						
5005-Operation Supervision and Engineering	0	0	0	0	0	0
5010-Load Dispatching	0	0	0	0	0	0
5012-Station Buildings and Fixtures Expense	0	0	0	0	0	0
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	659	1,013	354	171	1,013	842
5017-Distribution Station Equipment - Operation Supplies and Expenses	47,344	66,355	19,011	48,558	66,355	17,797
5020-Overhead Distribution Lines and Feeders - Operation Labour	2,078	3,758	1,680	3,242	3,758	516
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	174	1,080	906	1,607	1,080	(527)
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	0	3,558	3,558	1,108	3,558	2,450
5040-Underground Distribution Lines and Feeders - Operation Labour	1,241	1,492	251	1,119	1,492	373
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	548	270	(278)	242	270	28
5050-Underground Subtransmission Feeders - Operation	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	878	694	(184)	986	694	(291)
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0
5065-Meter Expense	74,472	103,931	29,460	86,151	103,931	17,781
5070-Customer Premises - Operation Labour	46,539	44,701	(1,837)	49,285	44,701	(4,583)
5075-Customer Premises - Materials and Expenses	29,011	19,505	(9,505)	14,660	19,505	4,845
5085-Miscellaneous Distribution Expense	39,128	156,263	117,135	124,310	156,263	31,953
5090-Underground Distribution Lines & Feeders-Rental Paid	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0
5096-Other Rent	6,736	6,325	(411)	7,482	6,325	(1,157)
Sub-Total	**248,806**	**408,946**	**160,139**	**338,920**	**408,946**	70,026
Maintenance						
5105-Maintenance Supervision and Engineering	53,982	128,570	74,588	90,555	128,570	38,016
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	(36,345)	11,345	47,691	18,743	11,345	(7,397)
5120-Maintenance of Poles, Towers and Fixtures	44,245	23,374	(20,871)	27,160	23,374	(3,786)
5125-Maintenance of Overhead Conductors and Devices	75,188	69,136	(6,052)	83,883	69,136	(14,747)
5130-Maintenance of Overhead Services	25,292	19,169	(6,122)	26,555	19,169	(7,386)
5135-Overhead Distribution Lines and Feeders - Right of Way	67,756	104,245	36,490	115,788	104,245	(11,543)
5145-Maintenance of Underground Conduit	46	0	(46)	0	0	0
5150-Maintenance of Underground Conductors and Devices	17,290	10,732	(6,558)	8,329	10,732	2,404
5155-Maintenance of Underground Services	49,114	80,437	31,323	68,555	80,437	11,881
5160-Maintenance of Line Transformers	29,632	45,413	15,782	17,313	45,413	28,101
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0
5170-Sentinel Lights - Labour	1,513	0	(1,513)	894	0	(894)
5172-Sentinel Lights- Materials and Expenses	928	0	(928)	225	0	(225)
5175-Maintenance of Meters	10,727	0	(10,727)	0	0	0
5178-Customer Installations Expenses - Leased Property	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0
Sub-Total	**339,366**	**492,423**	153,056	**457,999**	**492,423**	34,424

Billing and Collections

5305-Supervision	28,970	26,093	(2,878)	30,942	26,093	(4,850)
5310-Meter Reading Expense	92,682	114,976	22,294	97,875	114,976	17,101
5315-Customer Billing	186,772	238,412	51,640	210,800	238,412	27,612
5320-Collecting	122,015	160,472	38,457	137,665	160,472	22,807
5325-Collecting- Cash Over and Short	178	0	(178)	(485)	0	485
5330-Collection Charges	0	0	0	0	0	0
5335-Bad Debt Expense	46,042	20,000	(26,042)	24,916	20,000	(4,916)
5340-Miscellaneous Customer Accounts Expenses	0	0	0	0	0	0
Sub-Total	**476,660**	**559,953**	83,294	**501,713**	**559,953**	58,240

Community Relations

5405-Supervision	0	0	0	0	0	0
5410-Community Relations - Sundry	48,971	28,862	(20,110)	23,856	28,862	5,005
5415-Energy Conservation	102,620	0	(102,620)	18,695	0	(18,695)
5420-Community Safety Program	0	0	0	0	0	0
5510-Demonstrating and Selling Expense	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0
Sub-Total	**151,591**	**28,862**	(122,729)	**42,551**	**28,862**	(13,689)

Administrative and General Expenses

5605-Executive Salaries and Expenses	211,213	386,005	174,792	250,260	386,005	135,745
5610-Management Salaries and Expenses	144,703	132,149	(12,554)	153,939	132,149	(21,790)
5615-General Administrative Salaries and Expenses	55,885	270,196	214,311	134,014	270,196	136,182
5620-Office Supplies and Expenses	60,361	53,799	(6,563)	46,635	53,799	7,164
5625-Adminsitrative Expense Transferred-Credit	0	0	0	0	0	0
5630-Outside Services Employed	194,404	123,329	(71,075)	227,331	123,329	(104,002)
5635-Property Insurance	6,600	26,412	19,811	21,046	26,412	5,366
5640-Injuries and Damages	16,079	20,253	4,174	22,654	20,253	(2,401)
5645-Employee Pensions and Benefits	30,899	37,330	6,431	43,881	37,330	(6,551)
5650-Franchise Requirements	0	0	0	0	0	0
5655-Regulatory Expenses	8,456	77,072	68,616	44,408	77,072	32,664
5660-General Advertising Expenses	911	0	(911)	0	0	0
5665-Miscellaneous General Expenses	50,480	74,656	24,175	43,605	74,656	31,051
5670-Rent	2,450	0	(2,450)	0	0	0
5675-Maintenance of General Plant	66,178	77,632	11,453	79,173	77,632	(1,542)
5680-Electrical Safety Authority Fees	1,609	0	(1,609)	0	0	0
5685-Independent Market Operator Fees and Penalties	0	0	0	0	0	0
Sub-Total	**850,229**	**1,278,832**	428,602	**1,066,947**	**1,278,832**	211,885

Total Operating, Maintenance and Administration Expenses	**2,066,653**	**2,769,015**	702,362	**2,408,130**	**2,769,015**	360,885

2006 ACTUAL VERSUS 2006 BOARD APPROVED:

5017 - Distribution Station Equipment-Supplies & Expenses $26,840

In account 5017, Distribution Station Equipment costs increased by $26,840 due to misallocation of $11,000 in 2004 for wholesale meter reading costs to account 5310, Meter Reading that decreased (18,198). The costs in this account also increased by $5,000 for MSP charges that were not applicable in 2004.

5070 Customer Premises- Operation Labour $25,907

5075 Customer Premises- Operation Expenses (5,175)

This account collects costs associated with the location of underground services on customer premises. There was a greater volume of underground locates requests with a increase in labour costs of $13,000 and vehicle costs of $6,000 plus some additional material. These accounts are shown together due to recording vehicle expenses in the labour account 5070 that decreased the amount recorded in 5075.

5114 - Maintenance of Distribution Equipment ($45,479)

This account records the maintenance involved to keep distribution stations safe and maintain acceptable performance ratings as well as the wholesale metering costs that are not of an operational nature. The variance was a decrease in this account was because OHL’s service territories are embedded. As directed in the FAQ’s issued by the OEB once we received the 2005 and 2006 MSP rebates from Hydro One, the amount of $47,700 was recorded in this account.

5120 – Maintenance of Poles Towers, & Fixtures $28,049

This account collects costs associated with the repairing and replacing of fixtures, anchors etc. In 2006 there were material and labour charges amounting to $16,000 charged to this account that should have been capitalized.

5160 Maintenance of Line Transformers ($28,467)

Chlorinal testing for PCB content in transformers was not a true indicator of the PCB levels therefore we had to perform many oil samples in 2004 therefore there was a decrease in labour and material costs in 2006. OHL is completing the testing on an ongoing basis and we removed more PCB transformers in 2007.

5310 – Meter Reading ($18,198)

In account 5017, Distribution Station Equipment costs increased by $26,840 due to misallocation of $11,000 in 2004 for wholesale meter reading costs to account 5310, Meter Reading that decreased (18,198).

5335 Bad Debt Expense $22,907

OHL is diligent in the collection of accounts however a >50 kW general service customers of many years declared bankruptcy and left an amount owing of $38,000.

5410 Community Relations Sundry $24,014

OHL is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. OHL maintains a presence in the communities it serves, where OHL staff is available to answer customer questions in a friendly environment. OHL records community-related events such as the program for safety in the schools and participating in expos. OHL arranged for a consultant for our safety in the schools program for $9,000 a customer survey for $3,000. Labour associated with staff participation is also included in this account.

5415 Energy Conservation $102,620

This variance relates to the third tranche CDM spending of $103,000 spending in 2006. An offsetting amount was recorded as income in 2006.

5630 Outside Services $110,380

Expenses in this account relate to legal, audit services, IT assistance, human resource assistance, strategic planning. Prior to amalgamation of Grand Valley Energy and Orangeville Hydro, Grand Valley required increased dependence on financial and managerial assistance. In 2006 the increase in expenses in this account related to Grand Valley requiring additional financial and regulatory assistance for $15,000 and the contract with Orangeville Hydro for 6 months of the year amounting to $54,000. Other contributors to the increase were from investigation of activating a services company of $11,000, Hydro One Load data for $10,000 and an increase in our audit fees of $14,000.

5655 Regulatory Expenses (32,956)

The decrease in this account relates to the OEB Costs Assessment amount being recorded in account 1508.

5665 Miscellaneous General Expenses ($320,609)

The variance in this account mainly relates to the 2006 allocation of the Low Voltage $330,000

2007 ACTUAL VERSUS 2006 ACTUAL:

5017 – Distribution Station Equipment ($16,502)

The decrease relates to account 5114. The 2007 rebate of ($15,000) was posted to 5017 that created a credit balance in this account.

5065 - Meter Expense $37,411

Expenses in account 5065 increased while account 5175 decreased due to the account description of maintenance of meters in the Accounting handbook. It was concluded the OHL does not maintain meters as described under account 5175. OHL also hired a meter contractor to access and upgrade all 3-phase metering accounts to the Measurement Canada Standards at a cost of $22,000.

5114 – Maintenance of Distribution Station Equipment $38,078

The increase resulted from the 2006 actual variance of ($45,000) and the 2007 actual. In 2007 we received the 2005 rebate amounting to ($17,000) and accrued to 2006. The debit balance of $17,000 was offset by the 2007 rebate of ($18,000).

5155 Maintenance of Underground Services $35,087

OHL's total expenses increased compared to 2006 Actual amounts due to a large number of underground burnoffs experienced increasing labour by $19,000, vehicles $4,000 and contractors for an additional $2,000. OHL also wrote off obsolete inventory amounting to increase of $9,000 in 2007.

5160 Maintenance of Line Transformers $40,693

OHL discovered that all the transformers in the Grand Valley service area had never been tested for PCB content and were not compliant with the Ministry of the Environment regulations. Oil samples from each transformer were tested and OHL removed any transformer that didn't have acceptable levels. Labour $23,000, vehicles $6,000, contract $8,000 for lab testing with material of $4,000.

5175 - Maintenance of Meters ($10,727)

Expenses in account 5065 increased while account 5175 decreased due to the account description of maintenance of meters in the Accounting handbook. It was concluded the OHL does not maintain meters as described under account 5175.

5410 - Community Relations Sundry ($25,361)

OHL records community-related events such as the program for safety in the schools and participating in expos. Labour associated with staff participation is also included in this account. OHL did not run the safety in the school programs in 2007 thus the decrease.

5415 Energy Conservation $42,101

Again, variance relates to the third tranche CDM spending amounting to $144,721. An offsetting amount was recorded as income in 2007.

5615 – General Administration Salaries and Expenses $45,396

This account 5614 includes general administration staff and labour. The increase in account 5615 relates to the promotion of existing staff to a new position of Financial Assistant for $73,000 for a full year. There was shifting in positions and that led to reduction of ($4k) in account 5315 with the progression of another staff to the Senior Clerk position starting at the lower level. However, the amount in account 5315 and 5320 increased due to our CIS provider being sold and there were additional deregulation support charges of $17,000. A percentage of this expense is allocated to these accounts.

5655 – Regulatory Expenses $31,093

The variance in this account relates to the OEB Cost Assessment being recorded to 1508 in 2006.

2008 ACTUAL VERSUS 2007 ACTUAL:

5065 – Meter Expense ($25,732)

The decrease relates to the higher volume of meter changeouts performed meters in 2007 to be compliant with Measurement Canada. OHL changed the usual number of meters in 2008 that contributed to some of the decrease.

5085 – Miscellaneous Distribution Expense $90,123

The increase in this account resulted from the retirement of the line technician that was responsible to keep our mapping up to date and various other duties. Even with the position vacated the staff member on salary continuance to the end of the year. All of the expenses were booked to this account whereas usually the time would be directly allocated on a time sheet. There was also a vacation payout and retirement premium amounting to $23,000.

5105 – Maintenance of Supervision and Engineering $23,647

OHL included the time that the Manager of Operations spent supervising the line staff in the line overhead rate. The working foreman was spending more time in this role and the Manager of Operations time allocation increased in this account.

5135 – Overhead Distribution Lines & Feeders – RoW $64,118

This account collects costs associated with the clearing of overhead distribution lines. The main expense involves tree trimming performed by internal manpower. OHL's tree trimming is scheduled by designated areas in a revolving three year plan. As areas are not of equal size, costs can vary year to year.

5160 Maintenance of Line Transformers ($53,012)

One of the main activities in this account relates to the removal and testing of PCB transformers. In 2008, OHL's maintenance schedule was not as aggressive since the Grand Valley service area was never tested and had to be caught up to meet the Ministry of the Environment's regulations. Therefore there was a decrease in the amount of labour and expenses booked to this account.

5415 Energy Conservation ($126,026)

The remainder of the third tranche spending occurred in 2008 amounting to $18,695.

5605 – Executive Salaries and Expenses $33,072

This account records the salaries and expenses of the Board of directors and the President. The Board compensation was reviewed and compared to the compensation in other jurisdictions and an additional board member added in June 2008 resulting in an increase of $27,000.

5615 – General Administration Salaries and Expenses $32,732

This account includes general administration staff and labour. OHL hired an administrative assistant to assist with administrative duties and to coordinate the OPA Conservation and Demand programs where the position spends approximately 30% of their time amounting to $39,000. The time spent on these activities is allocated to account 43800 OPA Expenses. The hiring of an administrative assistant also allowed us to streamline staff duties and that were reassigned to allow staff to concentrate on the demands in the billing area.

5630 – Outside Services Employed $43,834

In 2008 the increase in this account was due to the hiring of a consultant to perform a valuation on the utility amounting to $18,000. OHL hired a consultant for $10,000 to work with the Board of Directors, Town council, legal and staff to further develop our strategic plan. There were also additional legal costs of $11,000 relating to the strategic plan and some of the costs for the merger were allocated to this account in error.

2009 BRIDGE YEAR VERSUS 2008 ACTUAL:

5085 – Miscellaneous Distribution Expense ($34,587)

The decrease relates to the retirement of the line technician from 2008 as the position remains vacant ($78,000). In 2009 we hired a consultant to complete our Asset Management Plan amounting to $41,000 and recorded the expenses in this account. Commencing 2009, OHL will record the salary and expenses of the Engineering Technician in this account. In the past, the Engineering Technician labour and expenses were included in the overhead rate charged in the direct labour of the lineman. In preparation of the movement towards International Financial Reporting Standards we will be recording the engineering department labour in this account and direct labour to capital accounts. Starting September 1, 2009 we will be hiring an engineering technician for an additional $20,000.

5105 – Maintenance of Supervision and Engineering $32,030

OHL included a percentage of the time that the Manager of Operations spent supervising the line staff in the line overhead rate. OHL removed this time relating to $15,000 from the overhead rate in preparation of the movement towards International Financial Reporting Standards. Due to amalgamation of Grand Valley and Orangeville there was an increase of $4,000 with to the shifting of payroll in this account. The managerial services to Grand Valley Energy no are no longer provided.

5605 – Executive Salaries and Expenses $107,638

In 2009 there was an additional Board member added due to the amalgamation of Grand Valley and Orangeville. In 2009, for succession planning, the Manager of Customer Service and Administration received a new title as Vice-President of Administration to assist the President with greater aspects involving the utility. This change decreased account 5610 by $60,000 and increased account 5605 amounting to $95,000 for salaries and expenses along with additional time allocation percentage in this account. Due to amalgamation of Grand Valley and Orangeville there was an increase of $29,000 with to the shifting of payroll in account 5610 and $5,000 in account 5605. The managerial services to Grand Valley Energy no are no longer provided

5610 – Management Salaries and Expenses ($24,756)

The decrease in this account relates to the increase in account 5605. The shifting of one position resulted in the salaries and expenses from account 5610 to 5605.

5615 – General Administration Salaries and Expenses $48,238

Due to amalgamation of Grand Valley and Orangeville there was an increase of $41,000 with to the shifting of payroll in this account. The managerial services to Grand Valley Energy are no longer provided.

5630 – Outside Services Employed ($129,692)

Due to Grand Valley and Orangeville there was a decrease of $89,000 in this account with the managerial services to Grand Valley Energy no longer provided. OHL decreased the budget in this account taking into consideration normalized spending for this account.

5665 – Miscellaneous General Expenses $26,621

The increase in this account relates to the increase in membership dues for the EDA of $8,000 due to an increase in our customer numbers from growth and the amalgamation and Cornerstone Electric Concepts (CHEC) of $17,000.

2010 TEST YEAR VERSUS 2009 BRIDGE YEAR:

5085 – Miscellaneous Distribution Expense $66,540

The increase in this account is due to the full year of the engineering technician $42,000 . OHL is restructuring the engineering department and plans to hire a junior engineer for $76,000 to implement and manage SCADA and GIS systems along with IT related activities.

5315 – Executive Salaries and Expenses $29,366

The increase in the account is attributable some of the costs for the new CIS system. The costs are more of an operational nature than capital where the system is hosted offsite. There are also some settlement costs referring to MicroFIT program.

5605 – Executive Salaries and Expenses $28,107

The increase in the account is attributable to the Vice President attending seminars and additional courses for educational purposes.

5615 – General Administration Salaries & Expenses $87,944

The variance over the 2009 Bridge Year is due to the addition of a regulatory assistant to assist with the increasing demands and regulatory interpretations and requirements of the OEB reporting for project such as rate filings, cost allocation, regulatory accounting, economic evaluations, the OEB quarterly and annual filings and distributed generation. We have budgeted $82,000.

5630 – Outside Services Employed $25,690

The increase is due to the implementation of the International Reporting Standards and assistance with the rate application. We have smoothed the cost of $100,00 over a four year period. All costs that are one-time costs or if over a period of time have been averaged in order to normalize the costs.

5655 – Regulatory Expenses $36,265

The increase is due to the 2010 cost of service filing. We have smoothed the cost of $140,000 over a four year period.

The table below sets out the OM&A cost per customer and Full Time equivalent employee.

Table 6

OM&A Cost per Customer and FTEE

	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Number of Customers	10,661	10,765	10,901	11,108	11,340
Total OMA	2,066,653	2,305,135	2,408,130	2,369,195	2,769,015
OMA cost per customer	194	214	221	213	244
Number of FTEEs	17	18	20	18	19
FTEEs/Customer	0	0	0	0	0
OMA cost per FTEE	121,568	128,063	120,407	131,622	145,738

OHL has not included any one-time costs in this application. Any costs that are incurred over a period of time have been averaged over the four year period of this cost of service rate application.

OHL has included the cost of the Low Income Assistance Program (LEAP) in account 5410 – Community Relations calculated as .12% of the 2010 Test year Revenue Requirement of **$5,362,234**

OHL has not included expenses that relate to the Green Energy Act

OHL did not include any charitable donations in our OM&A expenses.

Regulatory costs as indicated in the variance analysis are presented in Table 7. Regulatory costs for the 2010 rate application amounting to $140,000 have been considered over a four year period in our OM&A costs and the costs that have been included are highlighted below:

Table 7

Regulatory Costs

Regulatory Cost Category	Ongoing or One Time Cost?	Last Rebasing Year	Last Year of Actuals	Bridge Year	% Change in Bridge Year vs. Last Year of Actuals	Test Year Forecast	% Change in Test Year vs. Bridge Year
1. OEB Annual Assessment	Ongoing	36,181	28,826	31,632	9%	32,897	4%
2. OEB Hearing Assessments (applicant initiated)	Ongoing						
3. OEB Section 30 Costs (OEB initiated)	Ongoing		1,955	1,955	0%	50,000	96%
4. Expert Witness Cost for Regulatory Matters	One Time	-	-	-		5,000	100%
5. Legal Costs for Regulatory Matters	Ongoing	-	1,600	5,000	68%	10,000	50%
6. Consultants Costs for Regulatory Matters	Ongoing		1,425	20,000	93%	50,000	60%
7. Operating Expenses associated with Staff Resources Allocated to Regulatory Matters	Ongoing	47,936	71,800	77,500	7%	100,000	23%
8. Operating Expenses associated with other resources	Ongoing						
Total Regulatory Costs Included in Rate Application						140,000	

CHARGES TO AFFILIATES FOR SERVICES PROVIDED:

Introduction:

A summary of charges to affiliates for services provided in 2006 Actual and 2007 Actual, 2008 Actual together with the projections for the 2009 Bridge Year and 2010 Test Year, are shown in the following Table 3.

OHL currently performs water/sewer billing for the Town of Orangeville and water billing for the Village of Grand Valley. OHL bills the Town of Orangeville and the Village of East Luther-Grand Valley at a market rate by the number of customers. The market rate was researched by polling other LDC's that bill for water and adjusted in order to obtain a profit margin between 10% and 15%. In addition, OHL also performs streetlight maintenance. Water billing allocators are detailed in Table 1. For Streetlight Maintenance actual cost including labour, labour burden, stores material and burden, along with vehicle costs are charged and include a 10% profit mark up. OHL commenced water/sewer billing services for the Town of Orangeville in 2003. The Town paid the initial capital costs for the CIS vendor to set up the functionality and rates on our CIS system. OHL is currently implementing a new CIS system and the municipalities are contributing capital costs according to the functionality percentage of the system and therefore not included in the capital cost that OHL has presented in Exhibit 2.

As a result of recent changes to the Affiliate Relationships Code, OHL is reviewing its provision of services in respect of Street Light Maintenance.

Revenue from the above services are included Revenue Non Utility Operation (4375) is detailed in Exhibit 3, Tab 4, Schedules 1.

TABLE 8

SHARED SERVICES/CORPORATE COST ALLOCATION

Streetlight Maintenance

Name of Company				2006	2007	2008	2009	2010	2006	2007	2008	2009	2010	
From	To	Components of Service	Pricing Methodology	Price for the Service ($)					Cost for the Service ($)					% Allocation
OHL	Town of Orangeville	Labour	Cost Based						$28,693	$23,696	$31,919	$30,993	$31,816	100%
		Vehicles							$9,864	$7,452	$11,244	$10,421	$10,697	100%
		Materials							$25,392	$12,783	$18,208	$20,259	$20,797	100%
		Contractor							$136	$518	$883	$580	$596	100%
		Revenue	10% of Cost	$73,548	$48,860	$69,903	$73,346	$77,941						
Total Streetlight Maintenance				**$73,548**	**$48,860**	**$69,903**	**$73,346**	**$77,941**	**$64,086**	**$44,449**	**$62,254**	**$62,254**	**$63,905**	

Water Billing

Name of Company				2006	2007	2008	2009	2010	2006	2007	2008	2009	2010	
From	To	Components of Service	Pricing Methodology	Price for the Service ($)					Cost for the Service ($)					% Allocation
OHL	Town of Orangeville	Labour	Cost Based						$96,354	$87,772	$105,543	$115,056	$125,521	40%
		Office Supplies							$17,858	$18,653	$15,352	$20,840	$22,736	30%
		Building Maintenance							$8,079	$11,858	$13,777	$13,300	$14,509	25%
		Contractors							$21,305	$16,834	$31,604	$27,285	$29,767	40%
		Utilities/Property Taxes							$16,358	$18,549	$28,621	$24,875	$27,137	25%
		Postage/Stationery							$30,086	$29,537	$31,194	$36,202	$39,495	40%
		Meter Reading	# of reads						$28,844	$33,941	$32,872	$38,140	$41,609	
		Revenue-Water Billing	Market Rate x # of customers	$297,608	$309,564	$339,140	$335,665	$377,930						
		Revenue-Late Penalties	# of Late Penalties		$8,685	$16,805	$19,032	$19,317						
Total Water Billing				**$297,608**	**$318,249**	**$355,945**	**$354,696**	**$397,247**	**$218,884**	**$217,144**	**$258,964**	**$275,697**	**$300,774**	

Grand Valley

Streetlight Maintenance

Name of Company				2006	2007	2008	2009	2010		2006	2007	2008	2009	2010	
From	To	Components of Service	Pricing Methodology	Price for the Service ($)						Cost for the Service ($)					% Allocation
OHL	Township East Luther Grand Valley	Materials	Cost Based							$660	$2,047	$2,901	$2,220	$1,720	100%
		Contracts								$788	$509	$89	$771	$597	100%
		Revenue	10% of Cost	$935	$2,914	$3,187	$3,344	$3,553							
Total Streetlight Maintenance				**$935**	**$2,914**	**$3,187**	**$3,344**	**$3,553**		**$1,447**	**$2,556**	**$2,991**	**$2,991**	**$2,318**	

Water Billing

Name of Company				2006	2007	2008	2009	2010		2006	2007	2008	2009	2010	
From	To	Components of Service	Pricing Methodology	Price for the Service ($)						Cost for the Service ($)					% Allocation
OHL	Township East Luther Grand Valley	Contracts	Cost Based							$607	$5,643	$9,333	$9,989	$10,909	40%
		Revenue-Water Billing	Market Rate x # of customers	$6,500	$9,296	$10,887	$10,776	$12,133							
		Revenue-Late Penalties	# of Late Penalties		$470	$855	$968	$983							
Total Water Billing				**$6,500**	**$9,765**	**$11,742**	**$11,744**	**$13,116**		**$607**	**$5,643**	**$9,333**	**$9,989**	**$10,909**	

Purchase of Products and Services from Non-Affiliates:

Like other distributors, OHL purchases many services and products from third parties. The two tables below illustrate OHL's expenditures on purchased products and services are presented in Table 9.

Table 9

PURCHASE OF PRDUCTS AND SERVICES

Vendor Name	**2008 Purchases**	**2009 Purchases**	**2010 Purchases**
AESI Acumen Engineered Solutions Int ESA Consulting Quotation	$ 1,286.02	$ 1,315.60	$ 1,345.86
BackSpace Computer Services IT Services Cost Approach	$ 22,174.11	$ 22,684.11	$ 23,205.85
BDO Dunwoody Financial System Support Cost Approach	$ 23,417.15	$ 23,955.74	$ 24,506.73
BDO Dunwoody Orangeville Audit Firm Quotation	$ 29,583.75	$ 30,264.18	$ 30,960.25
BDR North America Inc Consulting Firm Quotation	$ 18,375.00		
Best Practice & Safety Compliance Safety Consultant Cost Approach	$ 9,560.00	$ 9,779.88	$ 10,004.82
Bestel Message Centre Ltd Answering Service Cost Approach	$ 3,102.30	$ 3,173.65	$ 3,246.65
Boldstar Infrared Services Inc Infrared Detection Cost Approach	$ 1,365.00	$ 1,396.40	$ 1,428.51
Borden Ladner Gervais LLP Rates, Legal Services Cost Approach	$ 22,707.61	$ 23,229.89	$ 23,764.17
Brink's Canada Ltd Banking Pick Up Service Cost Approach	$ 8,412.70	$ 8,606.19	$ 8,804.13
CHEC Group Membership Cost Approach	$ 11,521.71	$ 11,786.71	$ 12,057.80

Clean Start Cleaning Service Cleaning Quotation	$ 10,605.00	$ 10,848.92	$ 11,098.44
Elenchus Research Associates Consultant Cost Approach	$ 14,518.06		
Harris Computer Systems CIS Support & Operations Quotation	$ 15,587.47	$ 130,826.00	$ 133,835.00
Harris Computer Utility User Group User Group Cost Approach	$ 400.00	$ 409.20	$ 418.61
Mailing Innovations Ltd Bills/Inserter Machine Cost Approach	$ 3,872.10	$ 3,961.16	$ 4,052.26
Mono Arts & Graphics Printing Bill Paper & Envelopes Cost Approach	$ 23,439.81	$ 23,978.93	$ 24,530.44
Neopost Mailing Machine Cost Approach	$ 2,243.95	$ 2,295.56	$ 2,348.36
Olameter Inc Meter Reading Services Quotation	$ 3,584.36	$ 3,666.80	$ 3,751.14
On Call Postage Postage Machine Cost Approach	$ 18,963.00	$ 19,399.15	$ 19,845.33
Orangeville Insurance Insurance Quotation	$ 26,118.96	$ 26,719.70	$ 27,334.25
Paul Cowieson Grass Cutting Cost Approach	$ 3,130.00	$ 3,201.99	$ 3,275.64

Pearson & Associates Inc	$	5,957.00	$	6,094.01	$	6,234.17
Human Resources						
Cost Approach						
R.C. Whitney & Associates Ltd	$	15,728.69	$	16,090.45	$	16,460.53
Human Resources						
Cost Approach						
RCS Canada	$	11,707.50				
Consultant						
Cost Approach						
Reliable Technical Services	$	4,838.68	$	4,949.97	$	5,063.82
Ink Cartridges						
Cost Approach						
RODAN Energy & Metering Solutions	$	56,211.68	$	57,504.55	$	58,827.15
Metering Consultant						
Cost Approach						
Shred-it Canada	$	1,512.26	$	1,547.04	$	1,582.62
Shredding Service						
Cost Approach						
Stutz & Associates Professional Corp	$	43,826.92	$	44,834.94	$	45,866.14
Legal Services						
Cost Approach						
The SPi Group	$	9,821.60	$	10,047.50	$	10,278.59
EBT Provider						
Cost Approach						
Tiltran	$	16,814.74	$	17,201.48	$	17,597.11
Distribution Station Services						
Cost approach						
URB	$	101,052.20	$	103,376.40	$	105,754.06
Meter Reading						
Cost Approach						
Utilities Standards Forum	$	12,810.00	$	13,104.63	$	13,406.04
Engineering Specification						
Quotation						

Waste Management Waste Services Cost Approach	$	4,427.89	$	4,529.73	$	4,633.92
Weed Man Weed Control Quotation	$	2,229.10	$	2,280.37	$	2,332.82
Grand Totals:	**$**	**560,906.32**	**$**	**643,060.81**	**$**	**657,851.21**

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

OHL's Compensation/Performance System

Union

OHL's unionized staff is represented by the Power Workers Union. A formal set of contract negotiations was recently conducted and resulted in a new one year collective agreement effective October 1, 2008. The settlement included annual wage increases of 3% per year and a minor on-call increase beginning in October 1, 2008 and improvements to the benefits package. OHL's pay rates are competitive with other like-sized LDCs in the Georgian Bay District.

Executive/Management/non-union

In 2005, OHL implemented a new Management Performance & Compensation Plan for all salaried employees. The plan was developed by the assistance of an outside consulting firm, Pearson & Associates. Finalized job descriptions were evaluated using a proprietary Plan similar to the Hay Evaluation Plan and placed in pay bands ensuring internal equity. Pay market data was collected from Ontario's LDCs. A draft pay grid was developed from the available information and approved by the Board of Directors.

Individual job performance is aligned with the OHL's vision, mission, goals and strategic plan. A Management Performance Plan with annual targets is developed as part of the annual business plan. Management achievements are performance rated in four categories, exceptional, commendable, developing and satisfactory. Each category has a range for a percentage increase plus cost of living with the exception of an unsatisfactory performance. Once the job rate is achieved each category is compensated with an increase of cost of living and depending on the category rating a bonus for performance recognition may be granted. Actual performance compared to target is reviewed by senior management and the Board of Directors on an annual basis and used by the Compensation Committee as a basis for management compensation.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and a company-sponsored retirement plan. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and management employees.

Employee Compensation and Benefits:

OHL has set out the information in Table 10 below according to Section 6-4 of the 2006 EDR Handbook where it states "For an applicant with fewer than three employees, reporting of employee compensation under this section is not required. In cases where there are three or fewer, full time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer FTEs." OHL has aggregated the executive and management together in the management category. OHL's employee complement, compensation and benefits are set out in Table 10, below.

Change In Workforce Year Over Year:

Table 10 in Exhibit 4, Tab 2, Schedule 6 shows OHL's FTE headcount and compensation for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and 2010 Test Year.

2006 Board Approved to 2006 Actual

There was a decline in one management staff due to the departure of the Manager of the Grand Valley office. Due to the impending amalgamation of Orangeville and Grand Valley there was an addition to the union staff and a decline in the non union staff component.

The increase in total compensation was $90,000. The union contract negotiated in October 1, 2005 increased over 2004 3.5% for all union staff and management staff increase per management performance management. In 2005 management compensation was reviewed as part of the management review process. Also certain management staff received a bonus based on management achievement goals.

2006 Actual to 2007 Actual

Non-union increased by 1 staff from Union staff and Union increased by 1 staff. A new Line Apprentice was hired in November 2007. The addition on a non-union staff person was due to an existing staff person Senior Clerk was promoted to a new position in Management to Finance Assistant and a promotion from Customer Service Representative to Senior Clerk.

The increase in total compensation was $46,000. The union contract negotiated in October 1, 2006 resulted in a 3% increase that affected all union and management staff increase per management performance. There was a review of the leadhand rate and there was an additional increase of 1% for that staff person. Also there was movement of a leadhand to a working foreman that resulted in an additional 8% for that staff person. A review of one of the union positions led to an increase of 12.7%. Also certain management staff received a bonus based on management achievement goals and reached the top of the wage scale.

2007 Actual to 2008 Actual

Non-union increased by 1 employee. OHL hired a CDM/Administrative Assistant January, 2007 to manage the OPA programs and assist the President and management staff. Union staff increased by 1 employee. In June 2008 we hired a cashier to replace the cashier that was being trained for the Customer Service Representative position. There was a retirement of a Customer Service Representative December, 2008 and a retirement of a Line Technician effective December, 2008.

There was an increase in total compensation of $268,000. The increase is attributed to the new position of CDM/Administrative Assistant and the addition of the cashier for ½ a year. The union contract negotiated in October 1, 2007 resulted in a 3% increase that affected all union and management staff increase per management performance. Also certain management staff received a bonus based on management achievement goals.

2008 Actual to 2009 Bridge Year

Union staff decreased by 2 staff members with the two retirements at the end of 2008. There was a retirement of a customer service representative and a line technician. Engineering Technician has been replaced and expected to commence employment September, 2009. A temporary Administrative Assistant was hired to replace the existing incumbent who will fill in for a maternity leave.

Total compensation decreased by ($129,000). The decrease resulted from the departure of the Senior Engineering technician and not being replaced until September, 2009 by a junior position. The union contract negotiated in October 1, 2008 resulted in a 3% increase that affected all union and management staff increase per management performance. In 2009, the Manager of Administration and Customer Service was promoted to the Vice President of Administration that increased the hourly rate by 6% for that staff person. This promotion is part of succession planning with staff retention. In the next two and a half years 3 out of 4 senior management are eligible to retire and OHL needs to keep skilled employees. Also certain management staff are projected to receive a bonus based on management achievement goals.

2009 Bridge Year to 2010 Test Year

OHL plans to hire only 1 summer student. Increase in 2 non- union staff. In 2010 OHL has budgeted to hire a Regulatory Analyst and a Junior Engineer.

Total compensation increased by $279,000. The increase relates to the additional staff person of Regulatory Analyst and Junior Engineer. It is expected that the union negotiations will secure a 3% increase as well a $1.00 increase per hour wage adjustment on the lineman rate will be implemented to bring them up to the level of other like-sized LDCs. Progressions in the customer service depart as well as the VP Administration contributes to the increase. Also certain management staff are projected to receive a bonus based on management achievement goals.

Table 10

OHL – Employee Complement and Compensation

Number of Employees (FTEs) including Part-Time	2006	2007	2008	2009	2010
Executive					
Management	4	4	4	4	4
Non-Union	3	4	5	5	5
Union	13	13	14	12	12
Total	20	21	23	21	21

Number of Part Time Employees	2006	2007	2008	2009	2010
Executive					
Management					
Non-Union	3	3	3	3	1
Union					
Total	3	3	3	3	1

Total Salary and Wages					
Executive					
Management	373,810	391,909	407,359	430,619	462,541
Non-Union	39,751	73,012	121,730	151,320	258,535
Union	704,938	712,404	845,240	697,935	761,428
Total	1,118,498	1,177,325	1,374,329	1,279,874	1,482,505

Total Benefits					
Executive					
Management	75,945	71,236	83,966	86,016	95,309
Non-Union	3,289	15,059	30,715	29,930	67,573
Union	178,393	158,640	201,358	165,489	194,981
Total	257,627	244,935	316,039	281,436	357,863

Total Compensation	2006	2007	2008	2009	2010
Executive					
Management	449,755	463,145	491,325	516,635	557,850
Non-Union	43,040	88,071	152,445	181,250	326,109
Union	883,331	871,044	1,046,598	863,424	956,410
Total	1,376,125	1,422,260	1,690,368	1,561,309	1,840,368

Table 10

OHL – Employee Complement and Compensation

Compensation - Average Yearly Base Wages	2006	2007	2008	2009	2010
Executive					
Management	112,439	115,786	122,831	129,159	139,463
Non-Union	14,347	22,018	30,489	36,250	65,222
Union	67,949	67,003	74,757	71,952	79,701
Total	194,734	204,808	228,077	237,361	284,385

Compensation - Average Yearly Overtime	2006	2007	2008	2009	2010
Executive					
Management					
Non-Union					
Union	5,227	5,154	5,340	5,996	6,642
Total	5,227	5,154	5,340	5,996	6,642

Compensation - Average Yearly Incentive	2006	2007	2008	2009	2010
Executive					
Management	17,400	21,075	27,671	24,800	29,500
Non-Union					
Union					
Total	17,400	21,075	27,671	24,800	29,500

Compensation - Average Yearly Benefits	2006	2007	2008	2009	2010
Executive					
Management	18,986	21,369	28,146	28,512	36,631
Non-Union	628	205	419	379	182
Union	13,723	12,203	14,383	13,791	16,248
Total	33,337	33,777	42,948	42,682	53,061

	2006	2007	2008	2009	2010
Total Compensation	1,376,125	1,422,260	1,690,368	1,561,309	1,840,368
Total Compensation Charged to OM&A	973,527	985,895	1,177,418	1,244,124	1,525,010
Total Compensation Capitalized	190,232	170,054	188,529	197,525	191,868
Total Compensation Charged to Third Party	212,366	266,311	324,421	119,660	123,490

OMERS Pension Expense and Post Retiree Benefits:

OMERS Pension Expense:

OHL's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Accordingly, OHL has provided the OMERS pension premium information for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and the 2010 Test Year in Table 2 below.

Table 11
Pension Premium Information

OMERS	2006 Actual	2007 Actual	2008 Actual	2009 Bridge Yr	2010 Test Yr
Premiums Paid	157,514	175,251	195,879	176,255	213,209
Adjustments			- 4,565		
Pension Expense	157,514	175,251	191,313	176,255	213,209

Post-Retirement Benefits - Liability:

OHL has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and 2010 Test Year, in Table 3 below.

Post-Retirement Benefits - Premiums:

OHL pays certain health, dental, and life insurance benefits on behalf of its retired employees. Actual premiums paid for 2006 Actual, 2007 Actual, 2009 Bridge Year, and 2010 Test Year, are shown in Table 3 below.

Table 12
Post-Retirement Benefit Information

Orangeville Hydro Limited

Post-Retirement Benefits	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Bridge**	**2010 Test**
Premiums Paid	12,917	12,885	12,468	12,500	12,500
Change in Liability Account	22,646	23,710	36,567	28,318	28,470
Post-Retirement Benefit Expense	35,563	36,595	49,035	40,818	40,970

DEPRECIATION, AMORTIZATION AND DEPLETION:

Amortization on capital assets is calculated as follows:

- OHL uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:

- Prior to 2008 a full year's amortization was taken on capital additions during the current year. For 2008 and for this rate application OHL used the half year rule for calculating depreciation expense for the 2010 Test Year.

- Depreciation rates are in line with rates set out in the APH. A summary of those rates are as follows:

OEB Account	Description of Account	No. of Years
1805	Land	N/A
1806	Land Rights	25
1808	Buildings & Fixtures	25
1820	Municipal Distribution Station	30
1820	Wholesale Metering	30
1830	Poles, Towers and Fixtures	25
1835	Overhead Conductors and Devices	25
1840	Underground Conduit	25
1845	Underground Conductors and Devices	25
1855	Services	25
1850	Distribution Transformers	25
1860	Distribution Meters	25
1908	Buildings & Fixtures	50
1915	General Office Equipment	10
1920	Computer Equipment, Hardware	5
1925	Computer Software	5
1930	Trucks Under 3 Tons	5
1930	Trucks 3 Tons and Over	8
1930	Work and Service Equipment	8
1935	Stores Equipment	10
1940	Miscellaneous Equipment, Major Tools	10
1945	Measurement and Testing Equipment	10
1955	Communication Equipment	10
1960	Miscellaneous Equipment	10
1970	Load Management Controls - Customer Premises	10
1980	System Supervisory Equipment	15

Details of OHL's depreciation by account number are provided in the Fixed Asset Continuity Schedule in Exhibit 2, Tab 2, Schedule 1. OHL depreciation expense does not match the accumulated amortization because OHL expenses depreciation for overhead calculation for vehicles, stores, tools, measurement, and communication equipment. OHL has provided a reconciliation of depreciation expense to the Fixed Asset Continuity Schedule in Exhibit 2, Tab 2, Schedule 1 in the schedule below:

Table 13

Depreciation Expense

2006								
Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805	Land	29,126	29,126	0	0	0	0	0
1806	Land Rights	23,805	-3,027	26,831	6,056	29,859	25	1,194
1808	Buildings and Fixtures	15,296	15,296	0	0	0	0	0
1810	Leasehold Improvements	5,256	5,256	0	0	0	0	0
1815	Transformer Stn Equip-Normally Primary above 50kV	0	0	0	0	0	0	0
1820	Distribution Stn Equip-Normally Primary below 50kV	838,981	10,300	828,681	26,177	841,769	30	28,059
1825	Storage Battery Equipment	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	3,872,701	407,563	3,465,138	58,319	3,494,298	25	139,772
1835	Overhead Conductors and Devices	3,020,754	366,731	2,654,023	237,931	2,772,989	25	110,920
1840	Underground Conduit	2,974,027	256,932	2,717,094	-139,267	2,647,461	25	105,898
1845	Underground Conductors and Devices	2,991,839	-16,904	3,008,743	331,720	3,174,603	25	126,984
1850	Line Transformers	6,334,506	293,504	6,041,002	437,817	6,259,911	25	250,396
1855	Services	2,018,756	-174,179	2,192,935	78,764	2,232,317	25	89,293
1860	Meters	1,599,226	235,063	1,364,163	33,577	1,380,951	25	55,238
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0
1905	Land	144,400	144,400	0	0	0	0	0
1906	Land Rights	4,938	4,938	0	0	0	0	0
1908	Buildings and Fixtures	2,433,744	375,927	2,057,817	12,165	2,063,899	50	41,278
1910	Leasehold Improvements	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	154,454	85,511	68,942	0	68,942	10	6,894
1920	Computer Equipment - Hardware	269,629	175,000	94,629	27,519	108,389	5	21,678
1925	Computer Software	270,109	110,201	159,908	85,691	202,754	5	40,551
1930	Transportation Equipment	781,820	195,666	586,154	316,548	744,428	8	93,053
1935	Stores Equipment	26,359	17,119	9,240	0	9,240	10	924
1940	Tools, Shop and Garage Equipment	177,581	91,355	86,226	2,206	87,329	10	8,733
1945	Measurement and Testing Equipment	13,920	0	13,920	0	13,920	10	1,392
1950	Power Operated Equipment	0	0	0	0	0	0	0
1955	Communication Equipment	23,157	13,083	10,074	0	10,074	10	1,007
1960	Miscellaneous Equipment	9,700	322	9,378	0	9,378	10	938
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0
1980	System Supervisory Equipment	0	0	0	0	0	0	0
1985	Sentinel Lighting Rentals	9,804	8,019	1,784	0	1,784	10	178
1990	Other Tangible Property	0	0	0	0	0	0	0
1995	Contributions and Grants	-2,070,757	113,278	-2,184,035	-226,554	-2,297,312	25	-91,892
Total Accumulated Depreciation								**1,032,489**
Less:	Fully Allocated Depreciation							
1930	Transportation Equipment							93,053
1935	Stores Equipment							924
1940	Tools, Shop and Garage Equipment							8,733
1945	Measurement and Testing Equipment							1,392
1955	Communication Equipment							1,007
Net Depreciation								**927,379**

2007								
Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805	Land	29,126	29,126	0	0	0	0	0
1806	Land Rights	29,861	-1,978	31,839	3,956	33,817	25	1,353
1808	Buildings and Fixtures	15,296	15,296	0	0	0	0	0
1810	Leasehold Improvements	5,256	5,256	0	0	0	0	0
1815	Transformer Stn Equip-Normally Primary above 50kV	0	0	0	0	0	0	0
1820	Distribution Stn Equip-Normally Primary below 50kV	865,157	69,013	796,144	24,764	808,526	30	26,951
1825	Storage Battery Equipment	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	3,931,020	449,391	3,481,629	84,105	3,523,681	25	140,947
1835	Overhead Conductors and Devices	3,258,685	433,480	2,825,205	149,469	2,899,940	25	115,998
1840	Underground Conduit	2,834,760	63,795	2,770,965	247,003	2,894,467	25	115,779
1845	Underground Conductors and Devices	3,323,559	33,615	3,289,944	230,686	3,405,287	25	136,211
1850	Line Transformers	6,772,323	336,229	6,436,094	352,352	6,612,270	25	264,491
1855	Services	2,097,520	-183,330	2,280,849	102,075	2,331,887	25	93,275
1860	Meters	1,632,803	198,112	1,434,690	135,383	1,502,382	25	60,095
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0
1905	Land	144,400	144,400	0	0	0	0	0
1906	Land Rights	4,938	4,938	0	0	0	0	0
1908	Buildings and Fixtures	2,437,171	306,719	2,130,452	168,051	2,214,477	50	44,290
1910	Leasehold Improvements	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	153,410	68,944	84,465	34,559	101,745	10	10,174
1920	Computer Equipment - Hardware	221,379	78,814	142,565	14,090	149,610	5	29,922
1925	Computer Software	355,800	146,703	209,097	30,546	224,370	5	44,874
1930	Transportation Equipment	952,156	172,919	779,237	31,645	795,059	8	99,382
1935	Stores Equipment	26,359	10,021	16,338	5,668	19,172	10	1,917
1940	Tools, Shop and Garage Equipment	137,492	49,461	88,031	4,799	90,431	10	9,043
1945	Measurement and Testing Equipment	13,920	-700	14,620	1,399	15,320	10	1,532
1950	Power Operated Equipment	0	0	0	0	0	0	0
1955	Communication Equipment	19,323	9,249	10,074	0	10,074	10	1,007
1960	Miscellaneous Equipment	9,378	-624	10,001	2,131	11,067	10	1,107
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0
1980	System Supervisory Equipment	0	0	0	0	0	0	0
1985	Sentinel Lighting Rentals	9,804	8,288	1,515	0	1,515	10	152
1990	Other Tangible Property	0	0	0	0	0	0	0
1995	Contributions and Grants	-2,297,310	267,434	-2,564,744	-534,860	-2,832,174	25	-113,287
Total Accumulated Depreciation								**1,085,213**
Less:	Fully Allocated Depreciation							
1930	Transportation Equipment							99,382
1935	Stores Equipment							1,917
1940	Tools, Shop and Garage Equipment							9,043
1945	Measurement and Testing Equipment							1,532
1955	Communication Equipment							1,007
Net Depreciation								**972,331**

Orangeville Hydro Limited
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Exhibit 4
Tab 2
Schedule 7
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2008

Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805	Land	29,126	29,126	0	0	0	0	0
1806	Land Rights	33,817	0	33,817	0	33,817	25	1,353
1808	Buildings and Fixtures	15,296	15,296	0	0	0	0	0
1810	Leasehold Improvements	0	0	0	0	0	0	0
1815	Transformer Stn Equip-Normally Primary above 50kV	0	0	0	0	0	0	0
1820	Distribution Stn Equip-Normally Primary below 50kV	889,922	172,025	717,896	12,969	724,381	30	24,146
1825	Storage Battery Equipment	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	4,015,125	552,043	3,463,083	112,513	3,519,339	25	140,774
1835	Overhead Conductors and Devices	3,408,155	554,889	2,853,266	161,649	2,934,090	25	117,364
1840	Underground Conduit	3,081,763	187,296	2,894,467	317,537	3,053,235	25	122,129
1845	Underground Conductors and Devices	3,554,245	159,431	3,394,813	121,483	3,455,555	25	138,222
1850	Line Transformers	7,124,675	512,409	6,612,266	586,829	6,905,680	25	276,227
1855	Services	2,199,595	-126,556	2,326,151	31,435	2,341,868	25	93,675
1860	Meters	1,768,186	265,807	1,502,379	35,731	1,520,244	25	60,810
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0
1905	Land	144,400	144,400	0	0	0	0	0
1906	Land Rights	4,938	4,938	0	0	0	0	0
1908	Buildings and Fixtures	2,605,221	384,797	2,220,425	109,490	2,275,170	50	45,503
1910	Leasehold Improvements	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	187,159	92,592	94,567	2,632	95,883	10	9,588
1920	Computer Equipment - Hardware	217,915	153,139	64,775	8,778	69,165	5	13,833
1925	Computer Software	382,819	188,338	194,482	50,753	219,858	5	43,972
1930	Transportation Equipment	957,465	410,359	547,106	0	547,106	8	68,388
1935	Stores Equipment	32,027	22,564	9,463	910	9,918	10	992
1940	Tools, Shop and Garage Equipment	141,623	83,895	57,728	4,235	59,845	10	5,985
1945	Measurement and Testing Equipment	15,319	0	15,319	0	15,319	10	1,532
1950	Power Operated Equipment	0	0	0	0	0	0	0
1955	Communication Equipment	19,323	9,249	10,074	0	10,074	10	1,007
1960	Miscellaneous Equipment	11,066	2,395	8,671	11,876	14,609	10	1,461
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0
1980	System Supervisory Equipment	0	0	0	0	0	0	0
1985	Sentinel Lighting Rentals	9,804	8,139	1,664	0	1,664	10	166
1990	Other Tangible Property	0	0	0	0	0	0	0
1995	Contributions and Grants	-2,832,170	0	-2,832,170	-254,245	-2,959,292	25	-118,372
Total Accumulated Depreciation								**1,048,755**
Less:	Fully Allocated Depreciation							
1930	Transportation Equipment							68,388
1935	Stores Equipment							992
1940	Tools, Shop and Garage Equipment							5,985
1945	Measurement and Testing Equipment							1,532
1955	Communication Equipment							1,007
Net Depreciation								**970,851**

2009								
Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805	Land	29,126	29,126	0	0	0	0	0
1806	Land Rights	33,817	0	33,817	0	33,817	25	1,353
1808	Buildings and Fixtures	15,296	15,296	0	0	0	0	0
1810	Leasehold Improvements	0	0	0	0	0	0	0
1815	Transformer Stn Equip-Normally Primary above 50kV	0	0	0	0	0	0	0
1820	Distribution Stn Equip-Normally Primary below 50kV	902,891	184,995	717,896	7,382	721,587	30	25,113
1825	Storage Battery Equipment	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	4,127,638	664,556	3,463,083	146,908	3,536,537	25	146,750
1835	Overhead Conductors and Devices	3,569,804	716,538	2,853,266	148,936	2,927,734	25	125,349
1840	Underground Conduit	3,399,300	504,833	2,894,467	303,293	3,046,113	25	133,452
1845	Underground Conductors and Devices	3,675,728	280,915	3,394,813	370,611	3,580,119	25	148,153
1850	Line Transformers	7,711,503	1,099,238	6,612,266	650,758	6,937,645	25	314,483
1855	Services	2,231,030	-95,121	2,326,151	107,871	2,380,086	25	92,132
1860	Meters	1,803,916	301,538	1,502,379	15,630	1,510,194	25	62,179
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0
1905	Land	144,400	144,400	0	0	0	0	0
1906	Land Rights	4,938	4,938	0	0	0	0	0
1908	Buildings and Fixtures	2,711,924	491,500	2,220,425	17,000	2,228,925	50	46,961
1910	Leasehold Improvements	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	185,422	90,855	94,567	0	94,567	10	9,295
1920	Computer Equipment - Hardware	193,809	129,033	64,775	22,100	75,825	5	18,616
1925	Computer Software	433,572	239,090	194,482	216,144	302,554	5	81,999
1930	Transportation Equipment	957,465	469,623	487,842	130,000	552,842	8	69,105
1935	Stores Equipment	29,825	20,362	9,463	5,000	11,963	10	1,678
1940	Tools, Shop and Garage Equipment	145,858	88,130	57,728	5,000	60,228	10	4,427
1945	Measurement and Testing Equipment	15,319	0	15,319	1,000	15,819	10	1,358
1950	Power Operated Equipment	0	0	0	0	0	0	0
1955	Communication Equipment	19,323	9,249	10,074	0	10,074	10	1,007
1960	Miscellaneous Equipment	20,547	11,876	8,671	14,755	16,049	10	3,434
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0
1980	System Supervisory Equipment	0	0	0	0	0	0	0
1985	Sentinel Lighting Rentals	0	-1,664	1,664	0	1,664	10	0
1990	Other Tangible Property	0	0	0	0	0	0	0
1995	Contributions and Grants	-3,086,415	-254,246	-2,832,170	-458,562	-3,061,451	25	-142,011
Total Accumulated Depreciation								**1,144,835**
Less:	Fully Allocated Depreciation							
1930	Transportation Equipment							69,105
1935	Stores Equipment							1,678
1940	Tools, Shop and Garage Equipment							4,427
1945	Measurement and Testing Equipment							1,358
1955	Communication Equipment							1,007
Net Depreciation								**1,067,259**

2010								
Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805	Land	29,126	29,126	0	0	0	0	0
1806	Land Rights	33,817	3,028	30,788	0	30,788	25	1,353
1808	Buildings and Fixtures	15,296	15,296	0	0	0	0	0
1810	Leasehold Improvements	0	0	0	0	0	0	0
1815	Transformer Stn Equip-Normally Primary above 50kV	0	0	0	0	0	0	0
1820	Distribution Stn Equip-Normally Primary below 50kV	910,274	114,419	795,855	123,578	857,644	30	27,172
1825	Storage Battery Equipment	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	4,274,547	613,975	3,660,572	41,939	3,681,541	25	147,589
1835	Overhead Conductors and Devices	3,718,740	629,468	3,089,273	255,384	3,216,965	25	130,457
1840	Underground Conduit	3,702,592	179,880	3,522,713	233,544	3,639,485	25	138,123
1845	Underground Conductors and Devices	4,046,339	389,621	3,656,718	347,990	3,830,713	25	155,113
1850	Line Transformers	8,362,261	306,868	8,055,393	699,225	8,405,005	25	328,468
1855	Services	2,338,901	33,405	2,305,496	110,559	2,360,775	25	94,343
1860	Meters	1,819,546	248,865	1,570,681	90,971	1,616,166	25	63,999
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0
1905	Land	144,400	144,400	0	0	0	0	0
1906	Land Rights	4,938	4,938	0	0	0	0	0
1908	Buildings and Fixtures	2,728,924	381,975	2,346,949	10,000	2,351,949	50	47,061
1910	Leasehold Improvements	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	185,422	79,968	105,454	25,000	117,954	10	10,545
1920	Computer Equipment - Hardware	215,909	107,687	108,221	57,800	137,121	5	24,396
1925	Computer Software	649,716	253,177	396,539	118,780	455,929	5	93,877
1930	Transportation Equipment	1,087,465	660,397	427,068	65,000	459,568	8	73,168
1935	Stores Equipment	34,825	18,041	16,784	0	16,784	10	1,678
1940	Tools, Shop and Garage Equipment	150,858	105,188	45,669	5,000	48,169	10	4,677
1945	Measurement and Testing Equipment	16,319	2,237	14,082	1,000	14,582	10	1,408
1950	Power Operated Equipment	0	0	0	0	0	0	0
1955	Communication Equipment	19,323	9,249	10,074	0	10,074	10	1,007
1960	Miscellaneous Equipment	35,302	963	34,339	0	34,339	10	3,434
1970	Load Management Controls - Customer Premises	0	0	0	22,000	11,000	0	1,100
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0
1980	System Supervisory Equipment	0	0	0	15,000	7,500	0	500
1985	Sentinel Lighting Rentals	0	0	0	0	0	10	0
1990	Other Tangible Property	0	0	0	0	0	0	0
1995	Contributions and Grants	-3,544,977	35,936	-3,580,913	-287,833	-3,724,830	25	-147,768
Total Accumulated Depreciation								**1,201,701**
Less:	Fully Allocated Depreciation							
1930	Transportation Equipment							73,168
1935	Stores Equipment							1,678
1940	Tools, Shop and Garage Equipment							4,677
1945	Measurement and Testing Equipment							1,408
1955	Communication Equipment							1,007
Net Depreciation								**1,119,762**

TAX CALCULATIONS:

OHL’s detailed tax calculations using the most recent tax rates are provided in the following Table 7.

Table 17
Tax Calculations

Description	2006 Board Approved	2009 Bridge	2010 Test
Determination of Taxable Income			
Utility Income Before Taxes	715,726	771,944	818,422
Book to Tax Adjustments			
Additions to Accounting Income:			
Interest and penalties on taxes	36	0	0
Amortization of tangible assets	906,329	1,144,835	1,201,701
Amortization of intangible assets	0	0	0
Recapture of capital cost allowance from Schedule 8	0	0	0
Gain on sale of eligible capital property from Schedule 10	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	0	0	0
Loss on disposal of assets	0	0	0
Charitable donations	0	0	0
Taxable Capital Gains	0	0	0
Political Donations	0	0	0
Deferred and prepaid expenses	0	0	0
Capitalized interest	0	0	0
Post Employment Expenses	26,765	24,421	26,409
Transition Costs Deducted Prior Year	82,747	0	0
Total Additions	**1,015,877**	**1,169,257**	**1,228,110**
Deductions from Accounting Income:			
Gain on disposal of assets per financial statements	0	0	0
Capital cost allowance from Schedule 8	655,009	1,034,830	1,177,400
Terminal loss from Schedule 8	0	0	0
Cumulative eligible capital deduction from Schedule 10	11,988	9,409	8,750
Allowable business investment loss	0	0	0
Deferred and prepaid expenses	0	0	0
Scientific research expenses claimed in year	0	0	0
Tax reserves end of year	0	0	0
Reserves from financial statements - balance at beginning of year	0	0	0
Contributions to deferred income plans	0	0	0
Book income of joint venture or partnership	0	0	0
Equity in income from subsidiary or affiliates	0	0	0
Interest capitalized for accounting deducted for tax	5,985	0	0
Capital Lease Payments	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	0	0	0
Excess Interest (from Tab "Schedule 7-3")	7,410	0	0
Other Deductions	0	0	0
Total Deductions	**680,392**	**1,044,239**	**1,186,151**
Regulatory Taxable Income	**1,051,211**	**896,962**	**860,381**
First $500,000	5.50%	5.50%	5.50%
Remaining	18.25%	18.25%	18.25%
First $500,000		24.50%	23.50%
Remaining		37.25%	36.25%
Corporate Income Tax Rate	36.12%	30.14%	28.84%
Subtotal	**379,697**		
Less: R&D ITC (0.3)			
Regulatory Income Tax	**379,697**	**270,368**	**248,138**

Calculation of Utility Income Taxes

Income Taxes	379,697	270,368	248,138
Large Corporation Tax	11,427	0	0
Ontario Capital Tax	41,907	4,795	2,099
Total Taxes	**433,031**	**275,163**	**250,237**

Tax Rates

Federal Tax	22.12%	19.00%	18.00%
Provincial Tax	14.00%	14.00%	14.00%
Total Tax Rate	36.12%	33.00%	32.00%
Effective Tax Rate		30.14%	28.84%

Large Corporation Tax	**11,427**

Calculation of Ontario Capital Tax

Total Rate Base	18,968,876	17,130,975	17,799,123
Less Exemption	5,000,000	15,000,000	15,000,000
Taxable Capital /Deemed taxable capital	**13,968,876**	**2,130,975**	**2,799,123**
OCT Rate	0.300%	0.225%	0.075%
Ontario Capital Tax	**41,907**	**4,795**	**2,099**

Summary of Income Taxes

Description	**2006 Board Approved**	**2009 Bridge**	**2010 Test**
Income Taxes	379,697	270,368	248,138
Large Corporation Tax	11,427	0	0
Ontario Capital Tax	41,907	4,795	2,099
Total Taxes	**433,031**	**275,163**	**250,237**

CAPITAL COST ALLOWANCE:

OHL is providing Capital Cost Allowance continuity schedules for the 2009 Bridge Year (Table 18) and the 2010 Test Year (Table 19) as follows:

2009 Bridge Year Capital Cost Allowance: Table 8

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	**Distribution System - 1988 to 22-Feb-2005**	12,283,153	0	0	12,283,153	17,000	0	12,300,153	8,500	12,291,653	4%	491,666	11,808,487
2	**Distribution System - pre 1988**		0	0	0	0	0	0	0	0	6%	0	0
6	**Buildings (No footings below ground)**		0	0	0	0	0	0	0	0	10%	0	0
8	**General Office/Stores Equip**	102,242	0	0	102,242	20,755		122,997	10,377	112,619	20%	22,524	100,473
10	**Computer Hardware/ Vehicles**	203,181	0	0	203,181	135,000	14000	324,181	67,500	256,681	30%	77,004	247,177
10.1	**Certain Automobiles**		0	0	0	0	0	0	0	0	30%	0	0
12	**Computer Software**	25,377	0	0	25,377	216,144	0	241,521	108,072	133,449	100%	133,449	108,072
13 1	**Lease # 1**		0	0	0	0	0	0	0	0	20%	0	0
13 2	**Lease #2**		0	0	0	0	0	0	0	0		0	0
13 3	**Lease # 3**		0	0	0	0	0	0	0	0		0	0
13 4	**Lease # 4**		0	0	0	0	0	0	0	0		0	0
14	**Franchise**		0	0	0	0	0	0	0	0		0	0
17	**New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs**		0	0	0	0	0	0	0	0	8%	0	0
43.1	**Certain Energy-Efficient Electrical Generating Equipment**		0	0	0	0	0	0	0	0	30%	0	0
45	**Computers & Systems Hardware acq'd post Mar 22/04**	9,424	0	0	9,424		0	9,424	0	9,424	45%	4,241	5,183
50	**Computers & Systems Hardware acq'd post Mar 19/07**	10,610	0	0	10,610		0	10,610	0	10,610	55%	5,836	4,775
52	**Computers ac'd Jan 27-09 up to Feb 02-10**		0	0	0	22,100	0	22,100	11,050	11,050	100%	11,050	11,050
47	**Distribution System - post 22-Feb-2005**	2,966,839			2,966,839	1,292,828	0	4,259,667	646,414	3,613,253	8%	289,060	3,970,606
	SUB-TOTAL - UCC	**15,600,826**	**0**	**0**	**15,600,826**	**1,703,826**	**14,000**	**17,290,652**	**851,913**	**16,438,739**		**1,034,830**	**16,255,823**

CEC	**Goodwill**		0	0	0	**1,703,826**	check total
CEC	**Land Rights**	144533	0	0	144,533		
CEC	**FMV Bump-up**		0	0	0		
	SUB-TOTAL - CEC	**144,533**	**0**	**0**	**144,533**		

2009 Bridge Year Capital Cost Allowance: Table 8

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				134,416
<u>Additions:</u>				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	134,416
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				134,416
<u>Deductions:</u>				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	134,416
Cumulative Eligible Capital Balance				134,416
CEC Deduction	7%			9,409
Cumulative Eligible Capital - Closing Balance				125,007

2010 Test Year Capital Cost Allowance: Table 9

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	**Distribution System - 1988 to 22-Feb-2005**	11,808,487	0	0	11,808,487	10,000	0	11,818,487	5,000	11,813,487	4%	472,539	11,345,947
2	**Distribution System - pre 1988**	0	0	0	0	0	0	0	0	0	6%	0	0
6	**Buildings (No footings below ground)**	0	0	0	0	0	0	0	0	0	10%	0	0
8	**General Office/Stores Equip**	100,473	0	0	100,473	31,000	0	131,473	15,500	115,973	20%	23,195	108,278
10	**Computer Hardware/ Vehicles**	247,177	0	0	247,177	80,000	0	327,177	40,000	287,177	30%	86,153	241,024
10.1	**Certain Automobiles**	0	0	0	0	0	0	0	0	0	30%	0	0
12	**Computer Software**	108,072	0	0	108,072	118,780	0	226,852	59,390	167,462	100%	167,462	59,390
13 1	**Lease # 1**	0	0	0	0	0	0	0	0	0	20%	0	0
13 2	**Lease #2**	0	0	0	0	0	0	0	0	0		0	0
13 3	**Lease # 3**	0	0	0	0	0	0	0	0	0		0	0
13 4	**Lease # 4**	0	0	0	0	0	0	0	0	0		0	0
14	**Franchise**	0	0	0	0	0	0	0	0	0		0	0
43.2	**New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs**	0	0	0	0	-	0	0	0	0	50%	0	0
43.1	**Certain Energy-Efficient Electrical Generating Equipment**	0	0	0	0	0	0	0	0	0	30%	0	0
45	**Computers & Systems Hardware acq'd post Mar 22/04**	5,183	0	0	5,183		0	5,183	0	5,183	45%	2,332	2,851
45.1	**Computers & Systems Hardware acq'd post Mar 19/07**	4,775	0	0	4,775		0	4,775	0	4,775	55%	2,626	2,149
52	**Computers ac'd Jan 27-09 up to Feb 02-10**	11,050	0	0	11,050	57,800	0	68,850	28,900	39,950	100%	39,950	28,900
47	**Distribution System - post 22-Feb-2005**	3,970,606			3,970,606	1,637,357	0	5,607,963	818,679	4,789,285	8%	383,143	5,224,821
	SUB-TOTAL - UCC	**16,255,823**	**0**	**0**	**16,255,823**	**1,934,937**	**0**	**18,190,760**	**967,469**	**17,223,291**		**1,177,400**	**17,013,359**

CEC	**Goodwill**		0	0	0	1,934,937	Check total
CEC	**Land Rights**	125,007	0	0	125,007		
CEC	**FMV Bump-up**		0	0	0		
	SUB-TOTAL - CEC	**125,007**	**0**	**0**	**125,007**		

2010 Test Year Capital Cost Allowance: Table 9

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				125,007
Additions:				
Cost of Eligible Capital Property Acquired during the year				
Other Adjustments				
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002		x 1/2 =	0	
			0	125,007
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				125,007
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments				
Subtotal	0	x 3/4 =	0	125,007
Cumulative Eligible Capital Balance				125,007
CEC Deduction	7%			8,750
Cumulative Eligible Capital - Closing Balance				116,256

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2010 test years.

Capital Structure:

OHL has a current deemed capital structure of 56.7% debt with a return of 5.77%, and 43.3% equity with a return of 9% as approved in the 2009 IRM rate decisions in respect to OHL's service areas(EB-2008-0204 and EB-2008-0177).

OHL has prepared this rate application with a 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").

Return on Equity:

OHL is requesting a return on equity ("ROE") for the 2010 Test year of 8.01% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on March 7, 2009. OHL understands that the OEB will be finalizing the ROE for 2010 rates based on January 2010 market interest rate information. OHL's use of an ROE of 8.01% is without prejudice to any revised ROE that may be adopted by the OEB in early 2010.

Cost of Debt:

Long Term Debt

OHL is requesting a return on Long Term Debt for the 2010 Test Year of 6.46%. OHL is currently paying 5.59% on an existing Long Term Loan ($5,838,903) negotiated with the TD Canada Trust. In 2010, OHL has included a loan from Infrastructure Ontario to borrow $2,000,000 in capital to procure our Smart meters that we are expecting to implement in the Spring of 2010. Long-term debt cost information for the 2006 Board Approved, 2006, 2007 and 2008 Actual, and 2009 Bridge year are also provided in Exhibit 6, Tab 1, Schedule 3.

Short Term Debt

OHL is requesting a return on Short Term Debt for the 2010 Test year of 1.33% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on March 7, 2009. OHL understands that the OEB will be finalizing the return on short term debt for 2010 rates based on January 2010 market interest rate information. OHL's use of a Return on Short Term Debt of 1.33% is without prejudice to any revised ROE that may be adopted by the OEB in early 2010.

Rate Base and Rate of Return

Exhibit 5, Tab 1, Schedule 2 details OHL's rate base, deemed debt/equity ratios, deemed rate of return, actual debt/equity ratios and actual rates of returns for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year Forecast, and 2010 Test Year Forecast.

TABLE 1 - CAPITAL STRUCTURE DEEMED & ACTUAL

Capital Structure for 2006 Board Approved

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	7,964,442	50.00%	4.38%	348,842.58
Unfunded Short Term Debt				
Total Debt	7,964,442	50.00%		348,842.58
Common Share Equity	7,964,442	50.00%	9.00%	716,799.81
Total equity	7,964,442	50.00%		716,799.81
Total Rate Base	15,928,885	100%	6.69%	1,065,642.39

Capital Structure for 2006

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,065,566	50.00%	5.70%	459,973.11
Unfunded Short Term Debt				
Total Debt	8,065,566	50.00%		459,973.11
Common Share Equity	8,065,566	50.00%	9.00%	725,900.96
Total equity	8,065,566	50.00%		725,900.96
Total Rate Base	16,131,132	100%	7.35%	1,185,874.06

Capital Structure for 2007

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,200,465	50.00%	5.68%	465,893.45
Unfunded Short Term Debt				
Total Debt	8,200,465	50.00%		465,893.45
Common Share Equity	8,200,465	50.00%	9.00%	738,041.87
Total equity	8,200,465	50.00%		738,041.87
Total Rate Base	16,400,930	100%	7.34%	1,203,935.32

Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,778,943	53.30%	5.66%	496,675.70
Unfunded Short Term Debt				
Total Debt	8,778,943	53.30%		496,675.70
Common Share Equity	7,691,869	46.70%	9.00%	692,268.21
Total equity	7,691,869	46.70%		692,268.21
Total Rate Base	16,470,811	100%	7.22%	1,188,943.90

Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	9,713,263	56.70%	6.46%	627,053.36
Unfunded Short Term Debt	0	0.00%	0.00%	0.00
Total Debt	9,713,263	56.70%		627,053.36
Common Share Equity	7,417,712	43.30%	9.00%	667,594.09
Total equity	7,417,712	43.30%		667,594.09
Total Rate Base	17,130,975	100%	7.56%	1,294,647.45

Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	9,967,509	56.00%	6.46%	643,466.58
Unfunded Short Term Debt	711,965	4.00%	1.33%	9,469.13
Total Debt	10,679,474	60.00%		652,935.71
Common Share Equity	7,119,649	40.00%	8.01%	570,283.90
Total equity	7,119,649	40.00%		570,283.90
Total Rate Base	17,799,123	100%	6.87%	1,223,219.60

TABLE 2 – COST OF LONG-TERM DEBT

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Chartered Bank	Scotia Bank	N	July 10, 2002	7,900,000	10	5.77%	2006	455,830
Chartered Bank	TD Bank	N					2006	0
Chartered Bank	Scotia Bank	N	July 10, 2002	7,900,000	10	5.77%	2007	263,507
Chartered Bank	TD Bank	N	July 30, 2007	6,429,398	25	5.59%	2007	151,639
Chartered Bank	TD Bank	N	July 30, 2007	6,243,540	25	5.59%	2008	354,715
Chartered Bank	TD Bank	N					2008	0
Chartered Bank	TD Bank	N	July 30, 2007	6,063,061	25	5.59%	2009	343,023
Chartered Bank	TD Bank	N			25	5.66%	2009	0
Chartered Bank	TD Bank	N	July 30, 2007	5,838,903	25	5.59%	2010	331,688
Chartered Bank	InfraOntario	N	January 1, 2010	2,000,000	25	5.57%	2010	109,807

Total Long Term Debt Outstanding at end of 2006	7,900,000	**Total Interest Cost for 2006**	455,830
		Weighted Debt Cost Rate for 2006	5.77%
Total Long Term Debt Outstanding at end of 2007	7,279,527	**Total Interest Cost for 2007**	415,146
		Weighted Debt Cost Rate for 2007	5.70%
Total Long Term Debt Outstanding at end of 2008	6,243,540	**Total Interest Cost for 2008**	354,715
		Weighted Debt Cost Rate for 2008	5.68%
Total Long Term Debt Outstanding at end of 2009	6,063,061	**Total Interest Cost for 2009**	343,023
		Weighted Debt Cost Rate for 2009	5.66%
Total Long Term Debt Outstanding at end of 2010	6,838,903	**Total Interest Cost for 2010**	441,495
		Weighted Debt Cost Rate for 2010	6.46%

REVENUE DEFICIENCY - OVERVIEW:

OHL revenue deficiency is the result of increased OM&A expenses in 2010 with the increase in of 2 staff, new CIS costs, the cost of the 2010 rate application, the inclusion of costs for IFRS and the increase of our rate base from the 2006 EDR that was based on 2004 historical data. OHL has provided detailed calculations supporting its 2010 revenue deficiency. OHL's net revenue deficiency is $402,510 and when grossed up for PILs OHL's revenue deficiency is $631,388. Table 1 on the following page provides the revenue deficiency calculations for the 2010 Test Year at Existing 2009 OEB-approved rates and the 2010 Test Year Revenue Requirement.

Table 1
Calculation of Revenue Deficiency or Surplus

	2010 Test Existing Rates	2010 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$631,388
Distribution Revenue	$4,374,574	$4,374,574
Other Operating Revenue (Net)	$356,272	$356,272
Total Revenue	$4,730,846	$5,362,234
Distribution Costs		
Operation, Maintenance, and Administration	$2,769,015	$2,769,015
Depreciation & Amortization	$1,119,762	$1,119,762
Property & Capital Taxes	$2,099	$2,099
Interest- Deemed Interest	$652,936	$652,936
Total Costs and Expenses	$4,543,812	$4,543,812
Utility Income Before Income Taxes	$187,034	$818,422
Net Adjustments per 2009 Pils	$41,959	$41,959
Taxable Income	$228,993	$860,381
First $500,000	23.5%	23.5%
Remaining	36.25%	36.25%
Effective Tax Rate	8.41%	28.84%
Income Tax	$19,260	$248,138
Utility Net Income	$167,774	$570,284
Rate Base	$17,799,123	$17,799,123
Return on Equity	8.01%	8.01%
Equity Rate Base %	40.00%	40.00%
Equity Component Rate Base	$7,119,649	$7,119,649
Target Return -Equity on Rate Base	570,284	570,284
Revenue Deficiency	**$402,510**	**$0**
Revenue Deficiency (Gross-up)	**$631,388**	**$0**

COST ALLOCATION OVERVIEW:

Introduction:

On September 15, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. OHL prepared a cost allocation information filing consistent with OHL's understanding of the Directions, the Guidelines, the Model and the Instructions. OHL submitted this filing to the OEB on January 15, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

OHL has used the Board-approved Cost Allocation and updated the values from the Hydro One Run 2 load forecast using 2010 weather normalized forecasted data information. The updated 2010 forecast model is submitted in Exhibit 7, Tab 1, Schedule 1, Appendix A.

SUMMARY OF THE 2010 UPDATED RESULTS AND PROPOSED CHANGES:

INITIAL COST ALLOCATION STUDY RESULTS:

The data used in the Cost Allocation Model was consistent with OHL's cost data that supported its 2006 OEB-approved distribution rates. Consistent with the Guidelines, OHL's assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to OHL, its engineering records, and its customer and financial information systems.

As noted above, the results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following Table 1 outlines the revenue to cost ratios from the Cost Allocation Informational Filing submitted by OHL on January 15, 2007. The calculations are based on OHL's OEB-approved 2006 electricity distribution rates and the removal of the transformer allowance revenues and costs as per the Board's decisions during the 2009 cost of service rate applications.

Table 1
Revenue to Cost Ratios
2007 Cost Allocation Informational Filing

Rate Classification	Revenue (A)	Allocated Cost (B)	Revenue to Cost Ratio (A)/(B)
Residential	$2,843,950	$2,454,264	115.88%
GS <50 kW	$602,016	$667,094	90.24%
GS >50 kW to 4,999 kW	$719,235	$857,375	83.89%
Street Lighting	$8,654	$188,804	4.58%
Sentinel Lighting	$2,067	$13,776	15.01%
Unmetered Scattered Load	$22,111	$16,721	132.24%
Total	**$4,198,033**	**$4,198,032**	**100.00%**

2010 UPDATED COST ALLOCATION STUDY RESULTS:

OHL used the Board-approved Cost Allocation Model as included in Exhibit 7, Schedule 2, Appendix A. OHL followed the instructions and guidelines issued by the Board to enter the 2010 data into this model. OHL also conducted a review of the guidelines and found some anomalies with some of the original inputs into the model. It was discovered that OHL misinterpreted the guidelines when calculating the number of customers off the secondary. It was also noted that the number of streetlight connections should be calculated on a "connection" basis and not the number of streetlights. OHL has also made the changes to the transformer allowance treatment according to the decisions issued by the Board for the 2009 cost of service rate applications.

OHL populated the information on Sheet I3, Trial Balance Data with the 2010 forecasted data based 2009 and 2010 average and input the Target Net Income, PILs, Interest on Long Term debt, specific service charges information and the targeted revenue requirement and rate base. OHL did not include the transformer allowance as per the outcome of the decisions issued in the 2009 cost of service rate applications.

On Sheet I4, Break Out of Assets, OHL maintained the same break out of assets for 1830 and 1835 but found that the break out of out 1845 should have been 100% primary and we have changed on the updated model.

In Sheet I5, Miscellaneous data, OHL updated the road kilometers of distribution lines and changed the deemed equity component to be 40%. The service charge rates entered on this sheet are the proposed service charges for the 2010 rate application.

In Sheet I6, Customer Data, OHL entered all information updated with 2010 forecast data. OHL was able to obtain better information for the number of streetlight connections and the number of customers served off the secondary base. Transformer allowance was not included in the revenue for the >50 kW class.

OHL updated the meter information on Sheet I7.1 and the meter reading information on I7.2.

On sheet I8, Demand data is based on the output of our load forecast model. The load profile from the 2004 data received from Hydro One, Run 2 and the weather normalized 2010 forecast data was used to calculate the 1 NCP, 4 NCP, 12 NCP, 1 CP, 4 CP and the 12CP demand data. OHL used Run 2 of the Hydro One data in order to eliminate the >50 kW Time of Use class and maintain the Unmetered Scattered Load class.

No direct allocations were used.

The revenue to cost ratios for the 2010 updated study are provided in Table 2 below;

Table 2
Revenue to Cost Ratios from OHL's Updated 2010 Cost Allocation Model

Rate Classification	Revenue (A)	Allocated Cost (B)	Revenue to Cost Ratio (A)/(B)
Residential	$3,622,837	$3,186,267	113.70%
GS <50 kW	$889,251	$876,417	101.46%
GS >50 kW to 4,999 kW	$819,631	$1,128,289	72.64%
Street Lighting	$10,117	$137,645	7.35%
Sentinel Lighting	$2,723	$18,113	15.03%
Unmetered Scattered Load	$17,745	$15,573	113.95%
Total	**$5,362,304**	**$5,362,304**	**100.00%**

Proposed Adjustment to Cost Allocation:

On November 28, 2007, the OEB issued its "Report on Application of Cost Allocation for Electricity Distributors" (the "Cost Allocation Report"). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 3 below. Table 3 also provides OHL's proposed 2010 revenue to cost ratios. The proposed revenue to cost ratios reflect adjustments to revenue to address cross subsidization.

Table 3
OHL's Proposed Revenue to Cost Ratios

Rate Classification	OEB Low	OEB High	OHL Updated Cost Allocation Filing Results	OHL 2007 Cost Allocation Filing Results (no Transformer Ownership)	OHL 2007 Cost Allocation Filing Results (incl. Transformer Ownership)	OHL Proposed 2010 Revenue to Cost Ratios
Residential	85%	115%	113.70%	115.88%	114.10%	109.33%
GS <50 kW	80%	120%	101.46%	90.24%	87.69%	101.92%
GS >50 kW to 4,999 kW	80%	180%	72.64%	83.89%	91.73%	80.54%
Street Lighting	70%	120%	7.35%	4.58%	4.42%	38.52%
Sentinel Lighting	70%	120%	15.03%	15.01%	14.52%	42.53%
Unmetered Scattered Load	80%	120%	113.95%	132.24%	131.45%	102.34%

OHL is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring. The re-alignment will move those classes that are under contributing, to approximately 50% between their current ratio and target ratio. For example the current revenue to cost ratio for street lights is 7.35% moving the ratio to 38.52% means the proposed ratio is half way between 7.35% and 70%. The 70% being the low end of the OEB target range.

The additional revenue from the under contributing class will be distributed to those classes that are over contributing with the highest share being applied to the Residential class since this is the class that has the highest level of over contribution.

The following table outlines the revenue splits required to achieve the proposed revenue to cost ratios

Table 4

Revenue Split by Rate Class to Achieve Proposed Revenue to Cost Ratios

Rate Classification	Revenue Split to Achieve Proposed Revenue to Cost Ratio
Residential	64.72%
GS <50 kW	16.67%
GS >50 kW to 4,999 kW	17.20%
Street Lighting	0.98%
Sentinel Lighting	0.13%
Unmetered Scattered Load	0.30%
Total	100.00%

The following table outlines the three sets of revenue to cost ratios for each customer class

Table 5

Test Year Revenue Impacts

Rate Classification	Current Revenue	Test Year Revenue Assuming Current Revenue to Cost Ratios	Test Year Revenue Assuming Proposed Revenue to Cost Ratios
Residential	$2,951,855	$3,377,899	$3,239,709
GS <50 kW	$726,075	$830,871	$834,494
GS >50 kW to 4,999 kW	$675,143	$772,588	$861,026
Street Lighting	$5,452	$6,239	$49,159
Sentinel Lighting	$1,376	$1,575	$6,558
Unmetered Scattered Load	$14,673	$16,790	$15,018
Total	**$4,374,574**	**$5,005,962**	**$5,005,962**

Cost Allocation Summary:

The discussion and tables above support OHL's proposed reallocation of distribution revenues across customer classes, in order to begin moving toward revenue to cost ratios of 100% and reduce cross-subsidization. OHL submits that the proposed reallocation of distribution revenue is fair and reasonable for the following reasons:

- Customer class revenues will more closely reflect the actual costs of providing distribution service to that class;

- When necessary partial reallocation provides time for further refinement of the cost allocation model and movement between classes.

- The 2007 Cost Allocation study does not include Grand Valley. The original Orangeville Hydro case has been used as a starting point for the updated 2010 version.

Appendix A

2007 Cost Allocation

O1- Revenue to Cost Summary – No Transformer Allowance

Ontario

2006 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2005-0400 EB-2006-0247

Monday, January 15, 2007

Sheet O1 Revenue to Cost Summary Worksheet - Second 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)	**$3,896,274**	$2,641,669	$554,827	$676,601	$2,464	$1,415	$19,298
mi	Miscellaneous Revenue (mi)	**$301,759**	$202,281	$47,189	$42,634	$6,190	$652	$2,813
	Total Revenue	**$4,198,033**	**$2,843,950**	**$602,016**	**$719,235**	**$8,654**	**$2,067**	**$22,111**
	Expenses							
di	Distribution Costs (di)	**$427,911**	$240,453	$65,079	$99,775	$20,207	$1,398	$1,000
cu	Customer Related Costs (cu)	**$556,842**	$404,189	$83,270	$52,311	$10,958	$1,167	$4,946
ad	General and Administration (ad)	**$722,403**	$471,763	$108,969	$112,367	$23,082	$1,892	$4,328
dep	Depreciation and Amortization (dep)	**$877,034**	$475,858	$143,837	$205,546	$46,359	$3,211	$2,224
INPUT	PILs (INPUT)	**$473,758**	$253,048	$78,069	$113,718	$25,891	$1,793	$1,239
INT	Interest	**$445,382**	$237,891	$73,393	$106,907	$24,341	$1,686	$1,165
	Total Expenses	**$3,503,329**	**$2,083,203**	**$552,616**	**$690,623**	**$150,837**	**$11,146**	**$14,903**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	**$694,703**	$371,061	$114,477	$166,752	$37,966	$2,630	$1,817
	Revenue Requirement (includes NI)	**$4,198,032**	$2,454,264	$667,094	$857,375	$188,804	$13,776	$16,721

Revenue Requirement Input equals Output

Ontario

2006 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
EB-2005-0400 EB-2006-0247
Monday, January 15, 2007
Sheet O1 Revenue to Cost Summary Worksheet - Second Run

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$21,613,860	$11,626,124	$3,573,083	$5,129,943	$1,150,243	$79,613	$54,854
gp	General Plant - Gross	$4,183,080	$2,253,759	$690,632	$986,008	$226,199	$15,664	$10,818
accum dep	Accumulated Depreciation	($11,018,196)	($5,917,394)	($1,823,724)	($2,632,403)	($577,286)	($39,936)	($27,454)
co	Capital Contribution	($1,939,608)	($1,093,870)	($323,548)	($411,822)	($98,833)	($6,835)	($4,700)
	Total Net Plant	**$12,839,137**	**$6,868,620**	**$2,116,444**	**$3,071,726**	**$700,323**	**$48,507**	**$33,518**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$15,329,648	$5,189,114	$1,846,597	$8,129,922	$105,712	$9,340	$48,962
	OM&A Expenses	$1,707,156	$1,116,406	$257,319	$264,453	$54,247	$4,456	$10,275
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$17,036,803***	***$6,305,520***	***$2,103,916***	***$8,394,375***	***$159,959***	***$13,796***	***$59,237***
	Working Capital	**$2,555,521**	**$945,828**	**$315,587**	**$1,259,156**	**$23,994**	**$2,069**	**$8,886**
	Total Rate Base	**$15,394,657**	**$7,814,448**	**$2,432,031**	**$4,330,882**	**$724,317**	**$50,576**	**$42,403**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$7,697,329**	**$3,907,224**	**$1,216,015**	**$2,165,441**	**$362,158**	**$25,288**	**$21,202**
	Net Income on Allocated Assets	**$694,703**	**$760,747**	**$49,400**	**$28,612**	**($142,183)**	**($9,079)**	**$7,208**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$694,703**	**$760,747**	**$49,400**	**$28,612**	**($142,183)**	**($9,079)**	**$7,208**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	**100.00%**	115.88%	90.24%	83.89%	4.58%	15.01%	132.24%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$0**	$389,686	($65,078)	($138,140)	($180,149)	($11,709)	$5,390
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.03%	19.47%	4.06%	1.32%	-39.26%	-35.90%	34.00%

APPENDIX B

2010 Updated Cost Allocation Study

Ontario

Ontario Energy Board

2010 COST ALLOCATION INFORMATION FILING

Sheet I1 Utility Information Sheet

Name of LDC: Orangeville Hydro Limited

License Number: ED-2002-0500

EDR 2006 EB Number: EB-2002-0400 **Cost Allocation EB Number:** EB-2006-0247 drop

Date of Submission: Friday, August 28, 2009 **Version:** 1.2

Contact Information

Name: Jan Howard

Title: Manager of Finance & Rates

Phone Number: (519)942-8000

E-Mail Address: jhoward@orangevillehydro.on.ca

****Please Note: Colour Coding Legend****

Input Cells	
Output Cells	
Exhibition	
Brought Forward	Brought Forward
Calculation	Calculation
Default Numbers	
Diagnostic	

Brief Description of Each Worksheet's Function

INPUTS	I1	Intro	Brief explanation of what the pages do.
	I2	LDC data and Classes	Enter LDC specific information and number of classes etc
	I3	TB Data	Balance from approved 2006 EDR Trial Balance
	I4	BO ASSETS	Break out assets into detail functions - bulk deliver, primary and secondary
	I5	Misc Data	Input for miscellaneous data where necessary - TBD
	I6	Customer Data	Input customer related data for generating customer allocators
	I7.1	Meter Capital	Input meter related data for calculating capital costs weighing factors
	I7.2	Meter Reading	Input meter related data for calculating meter reading weighing factors
	I8	Demand Data	Input demand allocators using load data and making LDC specific adjustments
	I9	Direct Allocation	
OUTPUTS	O1	Revenue to cost	Output showing revenue to cost ratios, inter class subsidy etc.
	O2	Fixed Charge	Output showing the range for the Basic Customer charge - TBD
	O2.1	Line Transformer PLCC Adjustment	
	O2.2	Primary Cost PLCC Adjustment	
	O2.3	Secondary Cost PLCC Adjustment	
	O3.1	Line Tran Unit Cost	
	O3.2	Substat Tran Unit Cost	
	O3.3	Primary Cost Pool	
	O3.4	Secondary Cost Pool	
	O3.5	USL Metering Credit	
	O4	Summary by Class	Output showing summary of all allocation by class and by US of A
	O5	Detail by Class	Output showing details of individual allocation by class and by USofA
	O6	Source Data for E2	
	O7	Amortization	
EXHIBITS	E1	Categorization	Exhibit showing how costs are categorized
	E2	Allocation Factors	Exhibit summarizing all allocation factors created in I5 to I8 and present the findings in percentages
	E3	PLCC	Backup documentation for calculating Peak Load Carrying Capability.
	E4	Trial Balance Index	Exhibit showing 1. how accounts are grouped for reporting, how accounts are categorized and how accounts are allocated
	E5	Reconciliation	Exhibit showing reconciliation of accounts included and excluded from the allocation study to TB balance

Ontario

2010 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet I2 Class Selection - Second Run

Instructions:

Step 1: Pleae input your existing classes

Step 2: If this is your first run, select "First Run" in the drop-down menu below

Step 3: After all classes have been entered, Click the "Update" button in row E41

Click for Drop-Down Menu

If desired, provide a summary of this run (40 characters max.)

Second Run	

		Utility's Class Definition	Current
1	Residential		YES
2	GS <50		YES
3	GS>50-Regular		YES
4	GS> 50-TOU		NO
5	GS >50-Intermediate		NO
6	Large Use >5MW		NO
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		NO
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

** **Space available for additional information about this run**

2010 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
Friday, August 28, 2009

Sheet I3 Trial Balance Data - Second Run

Instructions:

Step 1: Copy 2006 EDR Trial Balance values (Sheet 2-4, Column P17 to P446) to Column D21 of this worksheet. Use the Edit - *Paste Special* - *Values* function.

Step 2: Enter the amounts needed to be reclassified to column F.

Step 3: Enter Target Net Income from approved EDR (Sheet 4-1, cell F23)

Step 4: Enter PILs from approved EDR (Sheet 4-2, cell E15)

Step 5: Enter Interest from approved EDR (Sheet 4-1, cell F21)

Step 6: Enter specific service charges offset from approved EDR (Sheet 5-5, cell D19)

Step 7: Enter Transformation Ownership Allowance Credit from approved EDR (Sheet 6-3, cell R120)

Step 8: Enter Low Voltage Wheeling Adjustment Credit from approved EDR (Sheet ADJ 3, cell F46)

Step 9: Enter Revenue Requirement from approved EDR (Sheet 5-1, cell F22)

Step 10: Enter Total Rate Base from approved EDR (Sheet 3-1, cell F21)

Step 11: Enter Directly Allocated amounts into column G.

2010 Test Year Net Income ($)	$570,284	Revenue Requirement Model - Return on Capital		
2010 PILs ($)	$250,237	Revenue Requirement Model - Revenue Requirement		
2010 Interest ($)	$652,936	Revenue Requirement Model - Return on Capital		
2010 Specific Service Charges ($)	$159,163	Revenue Requirement Model - Revenue Requirement		
Transformer Ownership Allowance ($)	$0	No input		
Low Voltage Wheeling Adjustment ($)	$0	No input - LV handled differently in 2006		
2010 Test year Revenue Requirement ($)	$5,362,234	**From this Sheet**	**Differences?**	
2010 Revenue Requirement to be Used in this model ($)	$ 5,362,234.00	**$5,362,234**	**Rev Req Matches**	
2010 Test Rate Base ($)	$17,799,123	Revenue Requirement Model - Return on Capital		
2010 Test Year Rate Base to be Used in this model ($)	$17,799,123	**$17,799,123**	**Rate Base Matches**	

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts		Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash						$0
1010	Cash Advances and Working Funds						$0
1020	Interest Special Deposits						$0
1030	Dividend Special Deposits						$0
1040	Other Special Deposits						$0
1060	Term Deposits						$0
1070	Current Investments						$0
1100	Customer Accounts Receivable						$0
1102	Accounts Receivable - Services						$0
1104	Accounts Receivable - Recoverable Work						$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.						$0
1110	Other Accounts Receivable						$0
1120	Accrued Utility Revenues						$0
1130	Accumulated Provision for Uncollectible Accounts--Credit						$0
1140	Interest and Dividends Receivable						$0
1150	Rents Receivable						$0
1170	Notes Receivable						$0
1180	Prepayments						$0
1190	Miscellaneous Current and Accrued Assets						$0
1200	Accounts Receivable from Associated Companies						$0
1210	Notes Receivable from Associated Companies						$0
1305	Fuel Stock						$0
1330	Plant Materials and Operating Supplies						$0
1340	Merchandise						$0
1350	Other Materials and Supplies						$0
1405	Long Term Investments in Non-Associated Companies						$0

1408	Long Term Receivable - Street Lighting Transfer					$0
1410	Other Special or Collateral Funds					$0
1415	Sinking Funds					$0
1425	Unamortized Debt Expense					$0
1445	Unamortized Discount on Long-Term Debt--Debit					$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses					$0
1460	Other Non-Current Assets					$0
1465	O.M.E.R.S. Past Service Costs					$0
1470	Past Service Costs - Employee Future Benefits					$0
1475	Past Service Costs - Other Pension Plans					$0
1480	Portfolio Investments - Associated Companies					$0
1485	Investment in Associated Companies - Significant Influence					$0
1490	Investment in Subsidiary Companies					$0
1505	Unrecovered Plant and Regulatory Study Costs					$0
1508	Other Regulatory Assets					$0
1510	Preliminary Survey and Investigation Charges					$0
1515	Emission Allowance Inventory					$0
1516	Emission Allowances Withheld					$0
1518	RCVARetail					$0
1520	Power Purchase Variance Account					$0
1525	Miscellaneous Deferred Debits					$0
1530	Deferred Losses from Disposition of Utility Plant					$0
1540	Unamortized Loss on Reacquired Debt					$0
1545	Development Charge Deposits/ Receivables					$0
1548	RCVASTR					$0
1560	Deferred Development Costs					$0
1562	Deferred Payments in Lieu of Taxes					$0
1563	Account 1563 - Deferred PILs Contra Account					$0
1565	Conservation and Demand Management Expenditures and Recoveries					$0
1570	Qualifying Transition Costs					$0
1571	Pre-market Opening Energy Variance					$0
1572	Extraordinary Event Costs					$0
1574	Deferred Rate Impact Amounts					$0
1580	RSVAWMS					$0
1582	RSVAONE-TIME					$0
1584	RSVANW					$0
1586	RSVACN					$0
1588	RSVAPOWER					$0
1590	Recovery of Regulatory Asset Balances					$0
1605	Electric Plant in Service - Control Account					$0
1606	Organization					$0
1608	Franchises and Consents					$0
1610	Miscellaneous Intangible Plant					$0
1615	Land					$0
1616	Land Rights					$0
1620	Buildings and Fixtures					$0
1630	Leasehold Improvements					$0
1635	Boiler Plant Equipment					$0
1640	Engines and Engine-Driven Generators					$0
1645	Turbogenerator Units					$0
1650	Reservoirs, Dams and Waterways					$0
1655	Water Wheels, Turbines and Generators					$0
1660	Roads, Railroads and Bridges					$0
1665	Fuel Holders, Producers and Accessories					$0
1670	Prime Movers					$0
1675	Generators					$0
1680	Accessory Electric Equipment					$0
1685	Miscellaneous Power Plant Equipment					$0
1705	Land					$0
1706	Land Rights					$0
1708	Buildings and Fixtures					$0
1710	Leasehold Improvements					$0
1715	Station Equipment					$0
1720	Towers and Fixtures					$0
1725	Poles and Fixtures					$0
1730	Overhead Conductors and Devices					$0
1735	Underground Conduit					$0
1740	Underground Conductors and Devices					$0
1745	Roads and Trails					$0
1805	Land		29,126			$29,126
1806	Land Rights		33,817			$33,817
1808	Buildings and Fixtures		15,296			$15,296
1810	Leasehold Improvements					$0
1815	Transformer Station Equipment - Normally Primary above 50 kV					$0
1820	Distribution Station Equipment - Normally Primary below 50 kV		972,062			$972,062
1825	Storage Battery Equipment		0			$0
1830	Poles, Towers and Fixtures		4,295,516			$4,295,516
1835	Overhead Conductors and Devices		3,846,432			$3,846,432
1840	Underground Conduit		3,819,364			$3,819,364
1845	Underground Conductors and Devices		4,220,334			$4,220,334
1850	Line Transformers		8,711,874			$8,711,874
1855	Services		2,394,181			$2,394,181
1860	Meters		1,865,032			$1,865,032
1865	Other Installations on Customer's Premises					$0
1870	Leased Property on Customer Premises					$0
1875	Street Lighting and Signal Systems		0			$0

1905	Land		144,400			$144,400
1906	Land Rights		4,938			$4,938
1908	Buildings and Fixtures		2,733,924			$2,733,924
1910	Leasehold Improvements					$0
1915	Office Furniture and Equipment		197,922			$197,922
1920	Computer Equipment - Hardware		244,809			$244,809
1925	Computer Software		709,106			$709,106
1930	Transportation Equipment		1,119,965			$1,119,965
1935	Stores Equipment		34,825			$34,825
1940	Tools, Shop and Garage Equipment		153,358			$153,358
1945	Measurement and Testing Equipment		16,819			$16,819
1950	Power Operated Equipment		0			$0
1955	Communication Equipment		19,323			$19,323
1960	Miscellaneous Equipment		35,302			$35,302
1965	Water Heater Rental Units					$0
1970	Load Management Controls - Customer Premises		11,000			$11,000
1975	Load Management Controls - Utility Premises					$0
1980	System Supervisory Equipment		7,500			$7,500
1985	Sentinel Lighting Rental Units					$0
1990	Other Tangible Property					$0
1995	Contributions and Grants - Credit		(3,688,894)			($3,688,894)
2005	Property Under Capital Leases		0			$0
2010	Electric Plant Purchased or Sold		0			$0
2020	Experimental Electric Plant Unclassified		0			$0
2030	Electric Plant and Equipment Leased to Others		0			$0
2040	Electric Plant Held for Future Use		0			$0
2050	Completed Construction Not Classified--Electric		0			$0
2055	Construction Work in Progress--Electric		0			$0
2060	Electric Plant Acquisition Adjustment		0			$0
2065	Other Electric Plant Adjustment		0			$0
2070	Other Utility Plant		0			$0
2075	Non-Utility Property Owned or Under Capital Leases		0			$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment		(17,513,537)			($17,513,537)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles					$0
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment		0			$0
2160	Accumulated Amortization of Other Utility Plant		0			$0
2180	Accumulated Amortization of Non-Utility Property		0			$0
2205	Accounts Payable					$0
2208	Customer Credit Balances					$0
2210	Current Portion of Customer Deposits					$0
2215	Dividends Declared					$0
2220	Miscellaneous Current and Accrued Liabilities					$0
2225	Notes and Loans Payable					$0
2240	Accounts Payable to Associated Companies					$0
2242	Notes Payable to Associated Companies					$0
2250	Debt Retirement Charges(DRC) Payable					$0
2252	Transmission Charges Payable					$0
2254	Electrical Safety Authority Fees Payable					$0
2256	Independent Market Operator Fees and Penalties Payable					$0
2260	Current Portion of Long Term Debt					$0
2262	Ontario Hydro Debt - Current Portion					$0
2264	Pensions and Employee Benefits - Current Portion					$0
2268	Accrued Interest on Long Term Debt					$0
2270	Matured Long Term Debt					$0
2272	Matured Interest on Long Term Debt					$0
2285	Obligations Under Capital Leases--Current					$0
2290	Commodity Taxes					$0
2292	Payroll Deductions / Expenses Payable					$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.					$0
2296	Future Income Taxes - Current					$0
2305	Accumulated Provision for Injuries and Damages					$0
2306	Employee Future Benefits					$0
2308	Other Pensions - Past Service Liability					$0
2310	Vested Sick Leave Liability					$0
2315	Accumulated Provision for Rate Refunds					$0
2320	Other Miscellaneous Non-Current Liabilities					$0
2325	Obligations Under Capital Lease--Non-Current					$0
2330	Development Charge Fund					$0
2335	Long Term Customer Deposits					$0
2340	Collateral Funds Liability					$0
2345	Unamortized Premium on Long Term Debt					$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion					$0
2350	Future Income Tax - Non-Current					$0
2405	Other Regulatory Liabilities					$0
2410	Deferred Gains from Disposition of Utility Plant					$0
2415	Unamortized Gain on Reacquired Debt					$0
2425	Other Deferred Credits					$0
2435	Accrued Rate-Payer Benefit					$0
2505	Debentures Outstanding - Long Term Portion					$0
2510	Debenture Advances					$0
2515	Reacquired Bonds					$0
2520	Other Long Term Debt					$0
2525	Term Bank Loans - Long Term Portion					$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion					$0
2550	Advances from Associated Companies					$0
3005	Common Shares Issued					$0

3008	Preference Shares Issued						$0
3010	Contributed Surplus						$0
3020	Donations Received						$0
3022	Development Charges Transferred to Equity						$0
3026	Capital Stock Held in Treasury						$0
3030	Miscellaneous Paid-In Capital						$0
3035	Installments Received on Capital Stock						$0
3040	Appropriated Retained Earnings						$0
3045	Unappropriated Retained Earnings						$0
3046	Balance Transferred From Income			$0		$0	($570,284)
3047	Appropriations of Retained Earnings - Current Period						$0
3048	Dividends Payable-Preference Shares						$0
3049	Dividends Payable-Common Shares						$0
3055	Adjustment to Retained Earnings						$0
3065	Unappropriated Undistributed Subsidiary Earnings						$0
4006	Residential Energy Sales		(5,398,148)				($5,398,148)
4010	Commercial Energy Sales		0				$0
4015	Industrial Energy Sales		(7,807,895)				($7,807,895)
4020	Energy Sales to Large Users		0				$0
4025	Street Lighting Energy Sales		(114,330)				($114,330)
4030	Sentinel Lighting Energy Sales		(8,257)				($8,257)
4035	General Energy Sales		(2,499,983)				($2,499,983)
4040	Other Energy Sales to Public Authorities		0				$0
4045	Energy Sales to Railroads and Railways		0				$0
4050	Revenue Adjustment		0				$0
4055	Energy Sales for Resale		0				$0
4060	Interdepartmental Energy Sales		(205,513)				($205,513)
4062	Billed WMS		(1,694,433)				($1,694,433)
4064	Billed-One-Time		0				$0
4066	Billed NW		(1,235,637)				($1,235,637)
4068	Billed CN		(702,316)				($702,316)
4080	Distribution Services Revenue		(5,032,050)		$26,087		($5,005,962)
4082	Retail Services Revenues		(19,546)				($19,546)
4084	Service Transaction Requests (STR) Revenues		(443)				($443)
4090	Electric Services Incidental to Energy Sales				($26,087)		($26,087)
4105	Transmission Charges Revenue						$0
4110	Transmission Services Revenue		0				$0
4205	Interdepartmental Rents		0				$0
4210	Rent from Electric Property		(54,516)				($54,516)
4215	Other Utility Operating Income		0		($15,272)		($15,272)
4220	Other Electric Revenues		0				$0
4225	Late Payment Charges		(37,522)				($37,522)
4230	Sales of Water and Water Power		0				$0
4235	Miscellaneous Service Revenues		(159,163)	$159,163			($159,163)
4240	Provision for Rate Refunds		0				$0
4245	Government Assistance Directly Credited to Income		0				$0
4305	Regulatory Debits		0				$0
4310	Regulatory Credits		0				$0
4315	Revenues from Electric Plant Leased to Others		0				$0
4320	Expenses of Electric Plant Leased to Others		0				$0
4325	Revenues from Merchandise, Jobbing, Etc.		0				$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.		0				$0
4335	Profits and Losses from Financial Instrument Hedges		0				$0
4340	Profits and Losses from Financial Instrument Investments		0				$0
4345	Gains from Disposition of Future Use Utility Plant		0				$0
4350	Losses from Disposition of Future Use Utility Plant		0				$0
4355	Gain on Disposition of Utility and Other Property		(1,600)		$800		($800)
4360	Loss on Disposition of Utility and Other Property		0				$0
4365	Gains from Disposition of Allowances for Emission		0				$0
4370	Losses from Disposition of Allowances for Emission		0				$0
4375	Revenues from Non-Utility Operations		(491,857)		$491,857		($0)
4380	Expenses of Non-Utility Operations		377,906		($381,032)		($3,126)
4385	Non-Utility Rental Income						$0
4390	Miscellaneous Non-Operating Income		(500)				($500)
4395	Rate-Payer Benefit Including Interest		0				$0
4398	Foreign Exchange Gains and Losses, Including Amortization		0				$0
4405	Interest and Dividend Income		(44,810)		$2,387		($42,423)
4415	Equity in Earnings of Subsidiary Companies		0				$0
4505	Operation Supervision and Engineering						$0
4510	Fuel						$0
4515	Steam Expense						$0
4520	Steam From Other Sources						$0
4525	Steam Transferred--Credit						$0
4530	Electric Expense						$0
4535	Water For Power						$0
4540	Water Power Taxes						$0
4545	Hydraulic Expenses						$0
4550	Generation Expense						$0
4555	Miscellaneous Power Generation Expenses						$0
4560	Rents						$0
4565	Allowances for Emissions						$0
4605	Maintenance Supervision and Engineering						$0
4610	Maintenance of Structures						$0
4615	Maintenance of Boiler Plant						$0
4620	Maintenance of Electric Plant						$0
4625	Maintenance of Reservoirs, Dams and Waterways						$0
4630	Maintenance of Water Wheels, Turbines and Generators						$0
4635	Maintenance of Generating and Electric Plant						$0

4640	Maintenance of Miscellaneous Power Generation Plant					$0
4705	Power Purchased		15,828,613			$15,828,613
4708	Charges-WMS		1,694,433			$1,694,433
4710	Cost of Power Adjustments		0			$0
4712	Charges-One-Time		205,513			$205,513
4714	Charges-NW		1,235,637			$1,235,637
4715	System Control and Load Dispatching		0			$0
4716	Charges-CN		702,316			$702,316
4720	Other Expenses		0			$0
4725	Competition Transition Expense		0			$0
4730	Rural Rate Assistance Expense		0			$0
4805	Operation Supervision and Engineering					$0
4810	Load Dispatching					$0
4815	Station Buildings and Fixtures Expenses					$0
4820	Transformer Station Equipment - Operating Labour					$0
4825	Transformer Station Equipment - Operating Supplies and Expense					$0
4830	Overhead Line Expenses					$0
4835	Underground Line Expenses					$0
4840	Transmission of Electricity by Others					$0
4845	Miscellaneous Transmission Expense					$0
4850	Rents					$0
4905	Maintenance Supervision and Engineering					$0
4910	Maintenance of Transformer Station Buildings and Fixtures					$0
4916	Maintenance of Transformer Station Equipment					$0
4930	Maintenance of Towers, Poles and Fixtures					$0
4935	Maintenance of Overhead Conductors and Devices					$0
4940	Maintenance of Overhead Lines - Right of Way					$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs					$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails					$0
4960	Maintenance of Underground Lines					$0
4965	Maintenance of Miscellaneous Transmission Plant					$0
5005	Operation Supervision and Engineering		0			$0
5010	Load Dispatching		0			$0
5012	Station Buildings and Fixtures Expense		0			$0
5014	Transformer Station Equipment - Operation Labour		0			$0
5015	Transformer Station Equipment - Operation Supplies and Expenses		0			$0
5016	Distribution Station Equipment - Operation Labour		1,013			$1,013
5017	Distribution Station Equipment - Operation Supplies and Expenses		66,355			$66,355
5020	Overhead Distribution Lines and Feeders - Operation Labour		3,758			$3,758
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		1,080			$1,080
5030	Overhead Subtransmission Feeders - Operation		0			$0
5035	Overhead Distribution Transformers- Operation		3,558	$0		$3,558
5040	Underground Distribution Lines and Feeders - Operation Labour		1,492			$1,492
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses		270			$270
5050	Underground Subtransmission Feeders - Operation		0			$0
5055	Underground Distribution Transformers - Operation		694	$0		$694
5060	Street Lighting and Signal System Expense		0			$0
5065	Meter Expense		103,931			$103,931
5070	Customer Premises - Operation Labour		44,701			$44,701
5075	Customer Premises - Materials and Expenses		19,505			$19,505
5085	Miscellaneous Distribution Expense		156,263			$156,263
5090	Underground Distribution Lines and Feeders - Rental Paid		0			$0
5095	Overhead Distribution Lines and Feeders - Rental Paid		0			$0
5096	Other Rent		6,325			$6,325
5105	Maintenance Supervision and Engineering		128,570			$128,570
5110	Maintenance of Buildings and Fixtures - Distribution Stations		0			$0
5112	Maintenance of Transformer Station Equipment		0			$0
5114	Maintenance of Distribution Station Equipment		11,345			$11,345
5120	Maintenance of Poles, Towers and Fixtures		23,374			$23,374
5125	Maintenance of Overhead Conductors and Devices		69,136			$69,136
5130	Maintenance of Overhead Services		19,169			$19,169
5135	Overhead Distribution Lines and Feeders - Right of Way		104,245			$104,245
5145	Maintenance of Underground Conduit		0			$0
5150	Maintenance of Underground Conductors and Devices		10,732			$10,732
5155	Maintenance of Underground Services		80,437			$80,437
5160	Maintenance of Line Transformers		45,413	$0		$45,413
5165	Maintenance of Street Lighting and Signal Systems					$0
5170	Sentinel Lights - Labour					$0
5172	Sentinel Lights - Materials and Expenses					$0
5175	Maintenance of Meters					$0
5178	Customer Installations Expenses- Leased Property					$0
5185	Water Heater Rentals - Labour					$0
5186	Water Heater Rentals - Materials and Expenses					$0
5190	Water Heater Controls - Labour					$0
5192	Water Heater Controls - Materials and Expenses					$0

5195	Maintenance of Other Installations on Customer Premises					$0
5205	Purchase of Transmission and System Services					$0
5210	Transmission Charges					$0
5215	Transmission Charges Recovered					$0
5305	Supervision		26,093			$26,093
5310	Meter Reading Expense		114,976			$114,976
5315	Customer Billing		238,412			$238,412
5320	Collecting		160,472			$160,472
5325	Collecting- Cash Over and Short					$0
5330	Collection Charges		0			$0
5335	Bad Debt Expense		20,000			$20,000
5340	Miscellaneous Customer Accounts Expenses					$0
5405	Supervision					$0
5410	Community Relations - Sundry		28,862			$28,862
5415	Energy Conservation					$0
5420	Community Safety Program					$0
5425	Miscellaneous Customer Service and Informational Expenses					$0
5505	Supervision					$0
5510	Demonstrating and Selling Expense					$0
5515	Advertising Expense					$0
5520	Miscellaneous Sales Expense					$0
5605	Executive Salaries and Expenses		386,005			$386,005
5610	Management Salaries and Expenses		132,149			$132,149
5615	General Administrative Salaries and Expenses		270,196			$270,196
5620	Office Supplies and Expenses		53,799			$53,799
5625	Administrative Expense Transferred Credit		0			$0
5630	Outside Services Employed		123,329			$123,329
5635	Property Insurance		26,412			$26,412
5640	Injuries and Damages		20,253			$20,253
5645	Employee Pensions and Benefits		37,330			$37,330
5650	Franchise Requirements		0			$0
5655	Regulatory Expenses		77,072			$77,072
5660	General Advertising Expenses		0			$0
5665	Miscellaneous General Expenses		74,656	$0		$74,656
5670	Rent		0			$0
5675	Maintenance of General Plant		77,632			$77,632
5680	Electrical Safety Authority Fees		0			$0
5685	Independent Market Operator Fees and Penalties		0			$0
5705	Amortization Expense - Property, Plant, and Equipment		1,119,762			$1,119,762
5710	Amortization of Limited Term Electric Plant					$0
5715	Amortization of Intangibles and Other Electric Plant					$0
5720	Amortization of Electric Plant Acquisition Adjustments					$0
5725	Miscellaneous Amortization					$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs					$0
5735	Amortization of Deferred Development Costs					$0
5740	Amortization of Deferred Charges					$0
6005	Interest on Long Term Debt		441,495	($441,495)	$0	$652,936
6010	Amortization of Debt Discount and Expense		0			$0
6015	Amortization of Premium on Debt Credit		0			$0
6020	Amortization of Loss on Reacquired Debt		0			$0
6025	Amortization of Gain on Reacquired Debt--Credit		0			$0
6030	Interest on Debt to Associated Companies		0			$0
6035	Other Interest Expense		52,293			$52,293
6040	Allowance for Borrowed Funds Used During Construction--Credit		0			$0
6042	Allowance For Other Funds Used During Construction		0			$0
6045	Interest Expense on Capital Lease Obligations		0			$0
6105	Taxes Other Than Income Taxes					$0
6110	Income Taxes		248,138	($248,138)	$0	$250,237
6115	Provision for Future Income Taxes		0			$0
6205	Donations					$0
6210	Life Insurance					$0
6215	Penalties		0			$0
6225	Other Deductions		0			$0
6305	Extraordinary Income		0			$0
6310	Extraordinary Deductions		0			$0
6315	Income Taxes, Extraordinary Items		0			$0
6405	Discontinues Operations - Income/ Gains					$0
6410	Discontinued Operations - Deductions/ Losses					$0
6415	Income Taxes, Discontinued Operations					$0

$98,740

Reclassification has not been done correctly as the total does not add to zero

Asset Accounts Directly Allocated $0

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Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
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Sheet I4 Break Out Worksheet - Second Run

Enter Net Fixed Assets for 2010	**$14,433,794**

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization I

Please see Handbook for detailed instructions

RATE BASE AND DISTRIBUTION ASSETS

		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$0								-				
1805	Land	$29,126		($29,126)	-									
1805-1	Land Station >50 kV		0.00%	$0	-					-				
1805-2	Land Station <50 kV		100.00%	$29,126	29,126					29,126	$0			
1806	Land Rights	$33,817		($33,817)	-									
1806-1	Land Rights Station >50 kV		0.00%	$0	-					-				
1806-2	Land Rights Station <50 kV		100.00%	$33,817	33,817			$ (10,634)		23,183	$1,353			
1808	Buildings and Fixtures	$15,296		($15,296)	-									
1808-1	Buildings and Fixtures > 50 kV		0.00%	$0	-					-				
1808-2	Buildings and Fixtures < 50 KV		100.00%	$15,296	15,296			$ (15,296)		-				
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV		0.00%	$0	-					-				
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0		$0	-					-				
1820	Distribution Station Equipment - Normally Primary below 50 kV	$972,062		($972,062)	-					-				
1820-	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			$0	-					-				
1820-	Distribution Station Equipment - Normally Primary below 50 kV Primary)		80.61%	$783,580	783,580			$ (472,576)		311,004	$21,904			
1820-	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		19.39%	$188,483	188,483			$ (113,674)		74,809	$5,269			
1825	Storage Battery Equipment	$0		$0	-									
1825-	Storage Battery Equipment > 50 kV			$0	-					-				
1825-	Storage Battery Equipment <50 kV		100.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$4,295,516		($4,295,516)	-									
1830-	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-				
1830-	Poles, Towers and Fixtures - Primary		49.00%	$2,104,803	2,104,803	$ (12,810.31)	$ 3,148.24	$ (1,401,345)		693,796	$71,806			
1830-	Poles, Towers and Fixtures - Secondary		51.00%	$2,190,713	2,190,713	$ (13,333.17)	$ 3,276.74	$ (1,458,543)		722,114	$74,737			
1835	Overhead Conductors and Devices	$3,846,432		($3,846,432)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-					-				
1835-4	Overhead Conductors and Devices - Primary		80.00%	$3,077,146	3,077,146	$ (19,152.94)	$ 3,608.22	$ (1,580,684)		1,480,918	$103,599			
1835-5	Overhead Conductors and Devices - Secondary		20.00%	$769,286	769,286	$ (4,788.23)	$ 902.05	$ (395,171)		370,229	$25,900			
1840	Underground Conduit	$3,819,364		($3,819,364)	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-					-				
1840-4	Underground Conduit - Primary		100.00%	$3,819,364	3,819,364	$ (643,940.59)	$ 169,329.37	$ (1,742,963)		1,601,790	$ 112,301.09			
1840-5	Underground Conduit - Secondary		0.00%	$0	-					-				
1845	Underground Conductors and Devices	$4,220,334		($4,220,334)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-				
1845-4	Underground Conductors and Devices - Primary		100.00%	$4,220,334	4,220,334	$ (629,980.28)	$ 155,515.28	$ (2,012,538)		1,733,330	$129,871			
1845-5	Underground Conductors and Devices - Secondary		0.00%	$0	-	$ -	$ -	$ -		-	$0			
1850	Line Transformers	$8,711,874		$0	8,711,874	$ (1,777,827.55)	$ 400,057.00	$ (3,961,150)		3,372,953	$ 257,262.72			
1855	Services	$2,394,181		$0	2,394,181	$ (401,655.33)	$ 111,863.24	$ (1,496,772)		607,617	$ 78,265.03			
1860	Meters	$1,865,032		$0	1,865,032	$ (185,405.47)	$ 60,838.05	$ (1,085,136)		655,329	$ 56,581.35			
	Total	**$30,203,034**		**$0**	**$30,203,034**	**($3,688,894)**	**$908,538**	**($15,746,480)**	**$0**	**11,676,198**	**$938,849**	**$0**	**$0**	**$0**
	SUB TOTAL from I3	**$30,203,034**												

5705	5710	5715	5720

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2010 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited
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Sheet I4 Break Out Worksheet - Second Run

Enter Net Fixed Assets for 2010	**$14,433,794**

RATE BASE AND DISTRIBUTION ASSETS

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization I

		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1905	Land	$144,400			144,400			$ -		$ 144,400	$0			
1906	Land Rights	$4,938			4,938			$ (4,938)		$ -	$0			
1908	Buildings and Fixtures	$2,733,924			2,733,924			$ (827,219)		$ 1,906,705	$47,061			
1910	Leasehold Improvements	$0			-			$ -		$ -	$0			
1915	Office Furniture and Equipment	$197,922			197,922			$ (148,709)		$ 49,212	$10,545			
1920	Computer Equipment - Hardware	$244,809			244,809			$ (193,162)		$ 51,647	$24,396			
1925	Computer Software	$709,106			709,106			$ (459,862)		$ 249,244	$93,877			
1930	Transportation Equipment	$1,119,965			1,119,965			$ (839,610)		$ 280,355				
1935	Stores Equipment	$34,825			34,825			$ (25,186)		$ 9,639				
1940	Tools, Shop and Garage Equipment	$153,358			153,358			$ (138,167)		$ 15,191				
1945	Measurement and Testing Equipment	$16,819			16,819			$ (14,242)		$ 2,577				
1950	Power Operated Equipment	$0			-			$ -		$ -	$0			
1955	Communication Equipment	$19,323			19,323			$ (16,321)		$ 3,002				
1960	Miscellaneous Equipment	$35,302			35,302			$ (7,414)		$ 27,888	$3,434			
1970	Load Management Controls - Customer Premises	$11,000			11,000			$ (550)		$ 10,450	$1,100			
1975	Load Management Controls - Utility Premises	$0			-			$ -		$ -	$0			
1980	System Supervisory Equipment	$7,500			7,500			$ (250)		$ 7,250	$500			
1990	Other Tangible Property	$0			-			$ -		$ -	-			
2005	Property Under Capital Leases	$0			-			$ -		$ -				
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$5,433,191		$0	$5,433,191	$0	$0	$ (2,675,631)	$0	$2,757,560	$180,913	$0	$0	$0
	SUB TOTAL from I3	$5,433,191												
	I3 Directly Allocated	$0												
	Grand Total	$35,636,225		$0	$35,636,225	($3,688,894)	$908,538	($18,422,112)	$0	$14,433,758	$1,119,762	$0	$0	$0

To be Prorated

1995	Contributed Capital - 1995	($3,688,894)	
2105	Accumulated Depreciation - 2105	($17,513,537)	
2120	Accumulated Depreciation - 2120	$0	
	Total	**($21,202,431)**	
	Net Assets	**$14,433,794**	**Net Fixed Assets Match EDR**

$3,688,894	**Balanced**
$17,513,573	**Error out of balance**
$0	**Balanced**

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$1,119,762
5710	Amortization of Limited Term Electric Plant	$0
5715	Amortization of Intangibles and Other Electric Plant	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0
	Total Amortization Expense	**$1,119,762**

($1,119,762)	**Balanced**
$0	**Balanced**
$0	**Balanced**
$0	**Balanced**

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Orangeville Hydro Limited

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Sheet I5 Miscellaneous Data Worksheet - Second Run

kMs of Roads in Service Area Where Distribution Lines Exist **168.5** includes Grand Valley

Deemed Equity Component of Rate Base (%) **40%**

1	2	3	7	8	9
Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
17.46	33.52	264.94	0.81	1.91	6.40
1	1	1			

2010 COST ALLOCATION INFORMATION FILING
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Sheet I6 Customer Data Worksheet - Second Run

Total kWhs	249,029,139

Total kWs	298,639

Target 2010 Distribution Revenue ($)	$5,005,962	Base Revenue Requirement

			1	2	3	7	8	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data								
2010 Forecast Data kWh	**CEN**	249,029,139	84,928,233	38,954,924	122,840,423	1,798,732	129,899	376,928
2010 Forecast Data kW	**CDEM**	298,639			293,178	5,102	360	
2010 Forecast Data Transformer Allowance kW		150,219			150,219			
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	249,029,139	84,928,233	38,954,924	122,840,423	1,798,732	129,899	376,928
kWh - 2010 Forecast weather normalized amount		249,029,139	84,928,233	38,954,924	122,840,423	1,798,732	129,899	376,928

2010 Test Year Class Distribution Revenue	**CREV**	$5,005,962	$3,377,899	$830,871	$772,588	$6,239	$1,575	$16,790
Bad Debt Forecasted Average	**BDHA**	$9,467	$9,467	$0	$0	$0	$0	$0
Late Payment Forecasted Average	**LPHA**	$37,522	$27,849	$6,079	$3,535	$8	$8	$45
Weighting Factor - Services			1.0	2.0	10.0	0.0	0.0	0.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	1.0	1.0
Number of Bills	**CNB**	136,080	120,534	12,966	1,596	48	552	384
Number of Connections (Unmetered)	**CCON**	1,845				1,524	170	151
Forecasted Total Number of Customers excluding connections	**CCA**	11,258	10,045	1,081	133			
Bulk Customer Base	**CCB**	-						
Primary Customer Base	**CCP**	11,258	10,045	1,081	133			
Line Transformer Customer Base	**CCLT**	11,240	10,045	1,081	115			
Secondary Customer Base	**CCS**	10,474	10,045	420	9			
Weighted - Services	**CWCS**	10,975	10,045	840	90	-	-	-
Weighted Meter -Capital	**CWMC**	1,101,927	558,042	251,486	292,400	-	-	-
Weighted Meter Reading	**CWMR**	177,154	126,641	30,821	19,692	-	-	-
Weighted Bills	**CWNB**	158,622	120,534	25,932	11,172	48	552	384
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		5,005,962	3,377,899	830,871	772,588	6,239	1,575	16,790

Weather Normalized Data from Hydro

	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
kWh - 2010 Forecast weather normalized amount	249,985,645	**85,386,842**	39,100,585	123,192,658	1,798,732	129,899	376,928
2010 Test year Loss Factor		**1.0468**	**1.0468**	**1.0468**	**1.0468**	**1.0468**	**1.0468**

Bad Debt Data Forecast

Sheet ADJ5 rows 26 - 32, column E	-	-	-	-			
Sheet ADJ5 rows 26 - 32, column F	14,200	14,200	-	-			
Sheet ADJ5 rows 26 - 32, column G	14,200	14,200	-	-			
Three-year average	**9,467**	**9,467**	**-**	**-**	**-**	**-**	**-**

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2010 COST ALLOCATION INFORMATION
Orangeville Hydro Limited
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Sheet I7.1 Meter Capital Worksheet - Second Run

		Residential			GS <50			GS>50-Regular			Street Light			Sentinel			Unmetered Scattered Load			TOTAL		
		1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			51%			23%			27%			0%			0%			0%			100%
	Cost Relative to Residential Average Cost			1.00			4.19			39.57			-			-			-			1.76
	Total	10,045	558,042	55.55694685	1,081	251485.6469	232.7493261	133	292400	2198.496241	0	0	-	0	0	-	0	0	-	11258	1101927.4	97.87949898
Meter Types	**Cost per Meter (Installed)**																					
Single Phase 200 Amp - Urban	50	9,726	486,277			0			0			0			0			0		9,726	486277.3564	
Single Phase 200 Amp - Rural	150		0			0			0			0			0			0		0	0	
Central Meter	250		0		335	83731.46878			0			0			0			0		335	83731.46878	
Network Meter (Costs to be updated)	225	319	71,764		746	167754.1781			0			0			0			0		1,065	239518.5743	
Three-phase - No demand	210		0			0			0			0			0			0		0	0	
Smart Meters	300		0			0			0			0			0			0		0	0	
Demand without IT (usually three-phase)	500		0			0			0			0			0			0		0	0	
Demand with IT	2,100		0			0		106	222600			0			0			0		106	222600	
Demand with IT and Interval Capability - Secondary	2,300		0			0		26	59800			0			0			0		26	59800	
Demand with IT and Interval Capability - Primary	10,000		0			0		1	10000			0			0			0		1	10000	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0			0			0			0		0	0	
LDC Specific 1			0			0			0			0			0			0		0	0	
LDC Specific 2			0			0			0			0			0			0		0	0	
LDC Specific 3			0			0			0			0			0			0		0	0	

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Sheet I7.2 Meter Reading Worksheet - Second Run

Weighting Factors based on Contractor Pricing

Description		1			2			3			7			8			9					
		Residential			GS <50			GS>50-Regular			Street Light			Sentinel			Unmetered Scattered Load			TOTAL		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			71.49%			17.40%			11.12%			0.00%			0.00%			0.00%			100.00%
	Cost Relative to Residential Average Cost			1.00			2.26			11.74			0.00			0.00			0.00			15.01
	Total	120,540	126,641	1.05	12,972	30,821	2.38	1,596	19,692	12.34	-	-	0	-	-	0	-	-	0	135,108	177,154	16
	Factor																					
Residential - Urban - Outside	1.00	7,917	7,917			0			0			0			0			0		7,917	7,917	
Residential - Urban - Outside with other services	1.00	105,870	105,870			0			0			0			0			0		105,870	105,870	
Residential - Urban - Inside	2.00	6,101	12,203			0			0			0			0			0		6,101	12,203	
Residential - Urban - Inside - with other services	1.00	651	651			0			0			0			0			0		651	651	
Residential - Rural - Outside	3.00		0			0			0			0			0			0		-	-	
Residential - Rural - Outside with other services	2.00		0			0			0			0			0			0		-	-	
LDC Specific 1			0			0			0			0			0			0		-	-	
LDC Specific 2			0			0			0			0			0			0		-	-	
GS - Walking	2.00		0		8,095	16,190			0			0			0			0		8,095	16,190	
GS - Walking - with other services	3.00		0		4,877	14,631			0			0			0			0		4,877	14,631	
GS - Vehicle with other services --- TOU Read	3.00		0			0			0			0			0			0		-	-	
GS - Vehicle with other services	3.00		0			0		1,272	3,816			0			0			0		1,272	3,816	
LDC Specific 3			0			0			0			0			0			0		-	-	
LDC Specific 4	0.00		0			0			0			0			0			0		-	-	
Interval	49.00		0			0		324	15,876			0			0			0		324	15,876	
LDC Specific 5			0			0			0			0			0			0		-	-	
LDC Specific 6			0			0			0			0			0			0		-	-	

20[illegible] COST ALLOCATION INFORMATION FILING

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Sheet I8 Demand Data Worksheet - Second Run

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

This is an input sheet for demand allocators.

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	41,428	17,458	6,025	17,462	419	30	34
Bulk Delivery CP	BCP1	41,428	17,458	6,025	17,462	419	30	34
Total Sytem CP	DCP1	41,428	17,458	6,025	17,462	419	30	34
4 CP								
Transformation CP	TCP4	162,643	64,738	27,024	69,363	1,258	91	170
Bulk Delivery CP	BCP4	162,643	64,738	27,024	69,363	1,258	91	170
Total Sytem CP	DCP4	162,643	64,738	27,024	69,363	1,258	91	170
12 CP								
Transformation CP	TCP12	457,465	169,200	81,291	203,311	2,936	212	515
Bulk Delivery CP	BCP12	457,465	169,200	81,291	203,311	2,936	212	515
Total Sytem CP	DCP12	457,465	169,200	81,291	203,311	2,936	212	515
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	48,889	18,896	10,396	19,100	419	30	48
Primary NCP	PNCP1	48,889	18,896	10,396	19,100	419	30	48
Line Transformer NCP	LTNCP1	46,215	18,896	10,396	16,426	419	30	48
Secondary NCP	SNCP1	24,785	18,896	4,054	1,337	419	30	48
4 NCP								
Classification NCP from Load Data Provider	DNCP4	186,426	72,316	37,090	75,035	1,678	121	186
Primary NCP	PNCP4	186,426	72,316	37,090	75,035	1,678	121	186
Line Transformer NCP	LTNCP4	175,921	72,316	37,090	64,530	1,678	121	186
Secondary NCP	SNCP4	94,018	72,316	14,465	5,252	1,678	121	186
12 NCP								
Classification NCP from Load Data Provider	DNCP12	510,523	191,223	95,022	218,367	5,033	363	515
Primary NCP	PNCP12	510,523	191,223	95,022	218,367	5,033	363	515
Line Transformer NCP	LTNCP12	479,951	191,223	95,022	187,795	5,033	363	515
Secondary NCP	SNCP12	249,479	191,223	37,058	15,286	5,033	363	515

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Sheet I9 Direct Allocation Worksheet - Second Run

Instructions:
To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line

Instructions:
The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
1995	Contributions and Grants - Credit	$0	Yes						
1805	Land	$0	Yes						
1806	Land Rights	$0	Yes						
1808	Buildings and Fixtures	$0	Yes						
1810	Leasehold Improvements	$0	Yes						
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes						
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes						
1825	Storage Battery Equipment	$0	Yes						
1830	Poles, Towers and Fixtures	$0	Yes						
1835	Overhead Conductors and Devices	$0	Yes						
1840	Underground Conduit	$0	Yes						
1845	Underground Conductors and Devices	$0	Yes						
1850	Line Transformers	$0	Yes						
1855	Services	$0	Yes						
1860	Meters	$0	Yes						
1905	Land	$0	Yes						
1906	Land Rights	$0	Yes						
1908	Buildings and Fixtures	$0	Yes						
1910	Leasehold Improvements	$0	Yes						
1915	Office Furniture and Equipment	$0	Yes						
1920	Computer Equipment - Hardware	$0	Yes						
1925	Computer Software	$0	Yes						
1930	Transportation Equipment	$0	Yes						
1935	Stores Equipment	$0	Yes						
1940	Tools, Shop and Garage Equipment	$0	Yes						
1945	Measurement and Testing Equipment	$0	Yes						
1950	Power Operated Equipment	$0	Yes						
1955	Communication Equipment	$0	Yes						
1960	Miscellaneous Equipment	$0	Yes						
1970	Load Management Controls - Customer Premises	$0	Yes						
1975	Load Management Controls - Utility Premises	$0	Yes						
1980	System Supervisory Equipment	$0	Yes						
1990	Other Tangible Property	$0	Yes						
2005	Property Under Capital Leases	$0	Yes						
2010	Electric Plant Purchased or Sold	$0	Yes						
2050	Completed Construction Not Classified--Electric	$0	Yes						
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	$0	Yes						
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes						
	Directly Allocated Net Fixed Assets			$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	Yes						
5010	Load Dispatching	$0	Yes						
5012	Station Buildings and Fixtures Expense	$0	Yes						
5014	Transformer Station Equipment - Operation Labour	$0	Yes						
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes						
5016	Distribution Station Equipment - Operation Labour	$0	Yes						
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes						
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes						
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes						
5030	Overhead Subtransmission Feeders - Operation	$0	Yes						
5035	Overhead Distribution Transformers- Operation	$0	Yes						
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	Yes						
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	Yes						
5050	Underground Subtransmission Feeders - Operation	$0	Yes						
5055	Underground Distribution Transformers - Operation	$0	Yes						
5065	Meter Expense	$0	Yes						

5070	Customer Premises - Operation Labour	$0	**Yes**						
5075	Customer Premises - Materials and Expenses	$0	**Yes**						
5085	Miscellaneous Distribution Expense	$0	**Yes**						
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	**Yes**						
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	**Yes**						
5096	Other Rent	$0	**Yes**						
5105	Maintenance Supervision and Engineering	$0	**Yes**						
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	**Yes**						
5112	Maintenance of Transformer Station Equipment	$0	**Yes**						
5114	Maintenance of Distribution Station Equipment	$0	**Yes**						
5120	Maintenance of Poles, Towers and Fixtures	$0	**Yes**						
5125	Maintenance of Overhead Conductors and Devices	$0	**Yes**						
5130	Maintenance of Overhead Services	$0	**Yes**						
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	**Yes**						
5145	Maintenance of Underground Conduit	$0	**Yes**						
5150	Maintenance of Underground Conductors and Devices	$0	**Yes**						
5155	Maintenance of Underground Services	$0	**Yes**						
5160	Maintenance of Line Transformers	$0	**Yes**						
5175	Maintenance of Meters	$0	**Yes**						
5305	Supervision	$0	**Yes**						
5310	Meter Reading Expense	$0	**Yes**						
5315	Customer Billing	$0	**Yes**						
5320	Collecting	$0	**Yes**						
5325	Collecting- Cash Over and Short	$0	**Yes**						
5330	Collection Charges	$0	**Yes**						
5335	Bad Debt Expense	$0	**Yes**						
5340	Miscellaneous Customer Accounts Expenses	$0	**Yes**						
5405	Supervision	$0	**Yes**						
5410	Community Relations - Sundry	$0	**Yes**						
5415	Energy Conservation	$0	**Yes**						
5420	Community Safety Program	$0	**Yes**						
5425	Miscellaneous Customer Service and Informational Expenses	$0	**Yes**						
5505	Supervision	$0	**Yes**						
5510	Demonstrating and Selling Expense	$0	**Yes**						
5515	Advertising Expense	$0	**Yes**						
5520	Miscellaneous Sales Expense	$0	**Yes**						
5605	Executive Salaries and Expenses	$0	**Yes**						
5610	Management Salaries and Expenses	$0	**Yes**						
5615	General Administrative Salaries and Expenses	$0	**Yes**						
5620	Office Supplies and Expenses	$0	**Yes**						
5625	Administrative Expense Transferred Credit	$0	**Yes**						
5630	Outside Services Employed	$0	**Yes**						
5635	Property Insurance	$0	**Yes**						
5640	Injuries and Damages	$0	**Yes**						
5645	Employee Pensions and Benefits	$0	**Yes**						
5650	Franchise Requirements	$0	**Yes**						
5655	Regulatory Expenses	$0	**Yes**						
5660	General Advertising Expenses	$0	**Yes**						
5665	Miscellaneous General Expenses	$0	**Yes**						
5670	Rent	$0	**Yes**						
5675	Maintenance of General Plant	$0	**Yes**						
5680	Electrical Safety Authority Fees	$0	**Yes**						
5705	Amortization Expense - Property, Plant, and Equipment	$0	**Yes**						
5710	Amortization of Limited Term Electric Plant	$0	**Yes**						
5715	Amortization of Intangibles and Other Electric Plant	$0	**Yes**						
5720	Amortization of Electric Plant Acquisition Adjustments	$0	**Yes**						
6105	Taxes Other Than Income Taxes	$0	**Yes**						
6205	Donations	$0	**Yes**						
6210	Life Insurance	$0	**Yes**						
6215	Penalties	$0	**Yes**						
6225	Other Deductions	$0	**Yes**						
	Total Expenses			$0	$0	$0	$0	$0	$0
	Depreciation Expense			$0	$0	$0	$0	$0	$0

Total Net Fixed Assets Excluding Gen Plant	**$30,203,034**	**Allocated**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Approved Total PILs	**$250,237**	**$0**	$0	$0	$0	$0	$0	$0
Approved Total Return on Debt	**$652,936**	**$0**	$0	$0	$0	$0	$0	$0
Approved Total Return on Equity	**$570,284**	**$0**	$0	$0	$0	$0	$0	$0
		Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

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Sheet O1 Revenue to Cost Summary Worksheet - Second 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)	**$5,005,962**	$3,377,899	$830,871	$772,588	$6,239	$1,575	$16,790
mi	Miscellaneous Revenue (mi)	**$356,272**	$244,053	$58,736	$47,556	$3,864	$1,145	$919
	Total Revenue	**$5,362,234**	**$3,621,952**	**$889,607**	**$820,144**	**$10,103**	**$2,720**	**$17,709**
	Expenses							
di	Distribution Costs (di)	**$733,231**	$420,691	$115,295	$173,429	$19,662	$2,200	$1,954
cu	Customer Related Costs (cu)	**$728,091**	$526,978	$118,494	$70,943	$7,596	$2,312	$1,769
ad	General and Administration (ad)	**$1,307,693**	$844,952	$209,428	$221,138	$24,771	$4,053	$3,350
dep	Depreciation and Amortization (dep)	**$1,119,762**	$611,716	$185,171	$278,857	$36,354	$4,055	$3,608
INPUT	PILs (INPUT)	**$250,237**	$132,814	$42,116	$65,179	$8,365	$933	$831
INT	Interest	**$652,936**	$346,546	$109,892	$170,069	$21,827	$2,434	$2,167
	Total Expenses	**$4,791,950**	**$2,883,696**	**$780,397**	**$979,615**	**$118,576**	**$15,987**	**$13,679**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	**$570,284**	$302,679	$95,981	$148,541	$19,064	$2,126	$1,893
	Revenue Requirement (includes NI)	**$5,362,234**	$3,186,375	$876,378	$1,128,156	$137,640	$18,113	$15,572
		Revenue Requirement Input equals Output						

Ontario

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Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$30,203,034	$16,433,577	$5,012,783	$7,578,986	$972,658	$108,469	$96,561
gp	General Plant - Gross	$5,433,191	$2,888,295	$914,017	$1,414,075	$179,061	$19,970	$17,772
accum dep	Accumulated Depreciation	($17,513,573)	($9,687,833)	($2,878,055)	($4,276,349)	($554,453)	($61,829)	($55,054)
co	Capital Contribution	($3,688,894)	($1,970,962)	($619,690)	($957,727)	($116,063)	($12,952)	($11,500)
	Total Net Plant	$14,433,758	$7,663,077	$2,429,055	$3,758,985	$481,203	$53,659	$47,779
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$19,666,513	$6,707,015	$3,076,377	$9,701,044	$142,051	$10,258	$29,767
	OM&A Expenses	$2,769,015	$1,792,620	$443,217	$465,509	$52,029	$8,566	$7,073
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$22,435,528*	*$8,499,635*	*$3,519,594*	*$10,166,554*	*$194,080*	*$18,824*	*$36,840*
	Working Capital	$3,365,329	$1,274,945	$527,939	$1,524,983	$29,112	$2,824	$5,526
	Total Rate Base	$17,799,087	$8,938,023	$2,956,994	$5,283,968	$510,315	$56,482	$53,305
		Rate Base Input Does Not Equal Output						
	Equity Component of Rate Base	$7,119,635	$3,575,209	$1,182,798	$2,113,587	$204,126	$22,593	$21,322
	Net Income on Allocated Assets	$570,284	$738,255	$109,210	($159,472)	($108,473)	($13,267)	$4,030
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$570,284	$738,255	$109,210	($159,472)	($108,473)	($13,267)	$4,030
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	113.67%	101.51%	72.70%	7.34%	15.02%	113.72%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	$435,577	$13,229	($308,013)	($127,537)	($15,393)	$2,137
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.01%	20.65%	9.23%	-7.55%	-53.14%	-58.72%	18.90%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary	1	2	3	7	8	9
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.04	$10.93	$60.58	$0.41	$1.01	$0.85
Customer Unit Cost per month - Directly Related	$8.77	$19.32	$104.25	$0.79	$1.99	$1.71
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$16.18	$24.42	$102.90	$7.50	$8.50	$8.26
Fixed Charge per approved 2006 EDR	$17.46	$33.52	$264.94	$0.81	$1.91	$6.40

Information to be Used to Allocate PILs, ROD, ROE and A&G		1	2	3	7	8	9
	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	$11,676,198	$6,197,153	$1,965,155	$3,041,286	$390,322	$43,523	$38,759
Total Administration and General Expense	$1,307,693	$844,952	$209,428	$221,138	$24,771	$4,053	$3,350
Total O&M	$1,454,997	$943,566	$232,777	$243,314	$27,141	$4,493	$3,707

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Distribution Plant							
1860	Meters	$1,865,032	$944,496	$425,644	$494,892	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($1,209,703)	($612,622)	($276,083)	($320,999)	$0	$0	$0
	Meter Net Fixed Assets	**$655,329**	**$331,874**	**$149,561**	**$173,894**	**$0**	**$0**	**$0**
	Misc Revenue							
4082	Retail Services Revenues	($19,546)	($14,853)	($3,195)	($1,377)	($6)	($68)	($47)
4084	Service Transaction Requests (STR) Revenues	($443)	($336)	($72)	($31)	($0)	($2)	($1)
4090	Electric Services Incidental to Energy Sales	($26,087)	($19,823)	($4,265)	($1,837)	($8)	($91)	($63)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($37,522)	($27,849)	($6,079)	($3,535)	($8)	($8)	($45)
	Sub-total	*($83,598)*	*($62,861)*	*($13,611)*	*($6,780)*	*($21)*	*($168)*	*($157)*
	Operation							
5065	Meter Expense	$103,931	$52,633	$23,720	$27,579	$0	$0	$0
5070	Customer Premises - Operation Labour	$44,701	$34,267	$3,686	$454	$5,199	$580	$515
5075	Customer Premises - Materials and Expenses	$19,505	$14,952	$1,608	$198	$2,269	$253	$225
	Sub-total	*$168,138*	*$101,853*	*$29,014*	*$28,230*	*$7,468*	*$833*	*$740*
	Maintenance							
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$114,976	$82,192	$20,003	$12,780	$0	$0	$0
5315	Customer Billing	$238,412	$181,165	$38,976	$16,792	$72	$830	$577
5320	Collecting	$160,472	$121,940	$26,234	$11,302	$49	$558	$388
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$513,861	$385,298	$85,214	$40,875	$121	$1,388	$966
	Total Operation, Maintenance and Billing	$681,999	$487,150	$114,228	$69,105	$7,588	$2,221	$1,706
	Amortization Expense - Meters	$56,581	$28,654	$12,913	$15,014	$0	$0	$0
	Allocated PILs	$11,360	$5,752	$2,593	$3,015	$0	$0	$0
	Allocated Debt Return	$29,642	$15,008	$6,766	$7,868	$0	$0	$0
	Allocated Equity Return	$25,890	$13,108	$5,910	$6,872	$0	$0	$0
	Total	**$721,874**	**$486,812**	**$128,799**	**$95,093**	**$7,567**	**$2,054**	**$1,549**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Distribution Plant							
1860	Meters	$1,865,032	$944,496	$425,644	$494,892	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($1,209,703)	($612,622)	($276,083)	($320,999)	$0	$0	$0
	Meter Net Fixed Assets	$655,329	$331,874	$149,561	$173,894	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$154,846	$78,504	$35,306	$41,036	$0	$0	$0
	Meter Net Fixed Assets Including General Plant	$810,175	$410,378	$184,867	$214,930	$0	$0	$0
	Misc Revenue							
4082	Retail Services Revenues	($19,546)	($14,853)	($3,195)	($1,377)	($6)	($68)	($47)
4084	Service Transaction Requests (STR) Revenues	($443)	($336)	($72)	($31)	($0)	($2)	($1)
4090	Electric Services Incidental to Energy Sales	($26,087)	($19,823)	($4,265)	($1,837)	($8)	($91)	($63)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($37,522)	($27,849)	($6,079)	($3,535)	($8)	($8)	($45)
	Sub-total	*($83,598)*	*($62,861)*	*($13,611)*	*($6,780)*	*($21)*	*($168)*	*($157)*
	Operation							
5065	Meter Expense	$103,931	$52,633	$23,720	$27,579	$0	$0	$0
5070	Customer Premises - Operation Labour	$44,701	$34,267	$3,686	$454	$5,199	$580	$515
5075	Customer Premises - Materials and Expenses	$19,505	$14,952	$1,608	$198	$2,269	$253	$225
	Sub-total	*$168,138*	*$101,853*	*$29,014*	*$28,230*	*$7,468*	*$833*	*$740*
	Maintenance							
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$114,976	$82,192	$20,003	$12,780	$0	$0	$0
5315	Customer Billing	$238,412	$181,165	$38,976	$16,792	$72	$830	$577
5320	Collecting	$160,472	$121,940	$26,234	$11,302	$49	$558	$388
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$513,861*	*$385,298*	*$85,214*	*$40,875*	*$121*	*$1,388*	*$966*
	Total Operation, Maintenance and Billing	$681,999	$487,150	$114,228	$69,105	$7,588	$2,221	$1,706
	Amortization Expense - Meters	$56,581	$28,654	$12,913	$15,014	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$10,159*	*$5,150*	*$2,316*	*$2,692*	*$0*	*$0*	*$0*
	Admin and General	$612,286	$436,237	$102,771	$62,807	$6,926	$2,004	$1,542
	Allocated PILs	$14,045	$7,113	$3,205	$3,727	$0	$0	$0
	Allocated Debt Return	$36,646	$18,558	$8,364	$9,724	$0	$0	$0
	Allocated Equity Return	$32,007	$16,209	$7,305	$8,493	$0	$0	$0
	Total	**$1,360,125**	**$936,211**	**$237,491**	**$164,782**	**$14,493**	**$4,058**	**$3,091**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Distribution Plant							
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$736,681	$564,722	$60,748	$7,478	$85,682	$9,562	$8,490
1830-5	Poles, Towers and Fixtures - Secondary	$766,750	$625,204	$26,142	$560	$94,859	$10,586	$9,399
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$1,077,001	$825,603	$88,811	$10,932	$125,265	$13,979	$12,411
1835-5	Overhead Conductors and Devices - Secondary	$269,250	$219,545	$9,180	$197	$33,310	$3,717	$3,300
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$1,336,778	$1,024,742	$110,233	$13,569	$155,479	$17,351	$15,405
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$1,477,117	$1,132,322	$121,805	$14,993	$171,801	$19,172	$17,022
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$2,613,562	$2,006,250	$215,815	$22,970	$304,398	$33,969	$30,160
1855	Services	$2,394,181	$2,191,293	$183,253	$19,634	$0	$0	$0
1860	Meters	$1,865,032	$944,496	$425,644	$494,892	$0	$0	$0
	Sub-total	*$12,536,351*	*$9,534,178*	*$1,241,632*	*$585,224*	*$970,794*	*$108,335*	*$96,188*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($8,064,431)	($6,118,151)	($807,730)	($433,674)	($582,169)	($64,934)	($57,773)
	Customer Related Net Fixed Assets	$4,471,920	$3,416,027	$433,901	$151,551	$388,625	$43,401	$38,415
	Allocated General Plant Net Fixed Assets	$1,055,778	$808,054	$102,428	$35,764	$90,485	$10,107	$8,940
	Customer Related NFA Including General Plant	$5,527,698	$4,224,081	$536,329	$187,314	$479,111	$53,508	$47,355
	Misc Revenue							
4082	Retail Services Revenues	($19,546)	($14,853)	($3,195)	($1,377)	($6)	($68)	($47)
4084	Service Transaction Requests (STR) Revenues	($443)	($336)	($72)	($31)	($0)	($2)	($1)
4090	Electric Services Incidental to Energy Sales	($26,087)	($19,823)	($4,265)	($1,837)	($8)	($91)	($63)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($37,522)	($27,849)	($6,079)	($3,535)	($8)	($8)	($45)
4235	Miscellaneous Service Revenues	($159,163)	($120,945)	($26,020)	($11,210)	($48)	($554)	($385)
	Sub-total	*($242,761)*	*($183,806)*	*($39,632)*	*($17,990)*	*($70)*	*($722)*	*($542)*

	Operating and Maintenance							
5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$1,315	$1,031	$85	$9	$157	$17	$16
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$378	$296	$25	$3	$45	$5	$4
5035	Overhead Distribution Transformers- Operation	$1,067	$819	$88	$9	$124	$14	$12
5040	Underground Distribution Lines and Feeders - Operation Labour	$522	$400	$43	$5	$61	$7	$6
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$95	$72	$8	$1	$11	$1	$1
5055	Underground Distribution Transformers - Operation	$208	$160	$17	$2	$24	$3	$2
5065	Meter Expense	$103,931	$52,633	$23,720	$27,579	$0	$0	$0
5070	Customer Premises - Operation Labour	$44,701	$34,267	$3,686	$454	$5,199	$580	$515
5075	Customer Premises - Materials and Expenses	$19,505	$14,952	$1,608	$198	$2,269	$253	$225
5085	Miscellaneous Distribution Expense	$54,692	$43,583	$4,258	$923	$4,896	$546	$486
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$45,000	$35,859	$3,503	$760	$4,028	$449	$400
5120	Maintenance of Poles, Towers and Fixtures	$8,181	$6,475	$473	$44	$982	$110	$97
5125	Maintenance of Overhead Conductors and Devices	$24,198	$18,786	$1,761	$200	$2,850	$318	$282
5130	Maintenance of Overhead Services	$19,169	$17,545	$1,467	$157	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$36,486	$28,617	$2,367	$245	$4,342	$485	$430
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$3,756	$2,880	$310	$38	$437	$49	$43
5155	Maintenance of Underground Services	$80,437	$73,620	$6,157	$660	$0	$0	$0
5160	Maintenance of Line Transformers	$13,624	$10,458	$1,125	$120	$1,587	$177	$157
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$457,266*	*$342,455*	*$50,701*	*$31,406*	*$27,012*	*$3,014*	*$2,678*
	Billing and Collection							
5305	Supervision	$26,093	$19,827	$4,266	$1,838	$8	$91	$63
5310	Meter Reading Expense	$114,976	$82,192	$20,003	$12,780	$0	$0	$0
5315	Customer Billing	$238,412	$181,165	$38,976	$16,792	$72	$830	$577
5320	Collecting	$160,472	$121,940	$26,234	$11,302	$49	$558	$388
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$20,000	$20,000	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$559,953*	*$425,125*	*$89,480*	*$42,712*	*$129*	*$1,479*	*$1,029*
	Sub Total Operating, Maintenance and Biling	*$1,017,219*	*$767,580*	*$140,181*	*$74,118*	*$27,141*	*$4,493*	*$3,707*
	Amortization Expense - Customer Related	$398,669	$302,086	$39,354	$20,442	$30,383	$3,389	$3,015
	Amortization Expense - General Plant assigned to Meters	$69,266	$53,013	$6,720	$2,346	$5,936	$663	$587
	Admin and General	$913,017	$687,359	$126,121	$67,363	$24,771	$4,053	$3,350
	Allocated PILs	$95,840	$73,210	$9,299	$3,248	$8,329	$930	$823
	Allocated Debt Return	$250,071	$191,025	$24,264	$8,475	$21,732	$2,427	$2,148
	Allocated Equity Return	$218,416	$166,844	$21,192	$7,402	$18,981	$2,120	$1,876
	PLCC Adjustment for Line Transformer	$74,434	$66,516	$7,156	$762	$0	$0	$0
	PLCC Adjustment for Primary Costs	$119,992	$107,391	$11,245	$1,356	$0	$0	$0
	PLCC Adjustment for Secondary Costs	$59,544	$53,483	$5,413	$648	$0	$0	$0
	Total	$2,465,765	**$1,829,921**	**$303,685**	**$162,638**	**$137,203**	**$17,354**	**$14,964**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 1,865,032	$ 944,496	$ 425,644	$ 494,892	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (1,209,703)	$ (612,622)	$ (276,083)	$ (320,999)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 655,329	$ 331,874	$ 149,561	$ 173,894	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (46,076)	$ (35,013)	$ (7,533)	$ (3,245)	$ (14)	$ (160)	$ (112)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (37,522)	$ (27,849)	$ (6,079)	$ (3,535)	$ (8)	$ (8)	$ (45)
Sub-total	$ (83,598)	$ (62,861)	$ (13,611)	$ (6,780)	$ (21)	$ (168)	$ (157)
Operation							
CWMC	$ 103,931	$ 52,633	$ 23,720	$ 27,579	$ -	$ -	$ -
CCA	$ 64,207	$ 49,219	$ 5,295	$ 652	$ 7,468	$ 833	$ 740
Sub-total	$ 168,138	$ 101,853	$ 29,014	$ 28,230	$ 7,468	$ 833	$ 740
Maintenance							
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 114,976	$ 82,192	$ 20,003	$ 12,780	$ -	$ -	$ -
CWNB	$ 398,885	$ 303,105	$ 65,211	$ 28,094	$ 121	$ 1,388	$ 966
Sub-total	$ 513,861	$ 385,298	$ 85,214	$ 40,875	$ 121	$ 1,388	$ 966
Total Operation, Maintenance and Billing	$ 681,999	$ 487,150	$ 114,228	$ 69,105	$ 7,588	$ 2,221	$ 1,706
Amortization Expense - Meters	$ 56,581	$ 28,654	$ 12,913	$ 15,014	$ -	$ -	$ -
Allocated PILs	$ 11,360	$ 5,752	$ 2,593	$ 3,015	$ -	$ -	$ -
Allocated Debt Return	$ 29,642	$ 15,008	$ 6,766	$ 7,868	$ -	$ -	$ -
Allocated Equity Return	$ 25,890	$ 13,108	$ 5,910	$ 6,872	$ -	$ -	$ -
Total	**$ 721,874**	**$ 486,812**	**$ 128,799**	**$ 95,093**	**$ 7,567**	**$ 2,054**	**$ 1,549**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 1,865,032	$ 944,496	$ 425,644	$ 494,892	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (1,209,703)	$ (612,622)	$ (276,083)	$ (320,999)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 655,329	$ 331,874	$ 149,561	$ 173,894	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 154,846	$ 78,504	$ 35,306	$ 41,036	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 810,175	$ 410,378	$ 184,867	$ 214,930	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (46,076)	$ (35,013)	$ (7,533)	$ (3,245)	$ (14)	$ (160)	$ (112)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (37,522)	$ (27,849)	$ (6,079)	$ (3,535)	$ (8)	$ (8)	$ (45)
Sub-total	*$ (83,598)*	*$ (62,861)*	*$ (13,611)*	*$ (6,780)*	*$ (21)*	*$ (168)*	*$ (157)*
Operation							
CWMC	$ 103,931	$ 52,633	$ 23,720	$ 27,579	$ -	$ -	$ -
CCA	$ 64,207	$ 49,219	$ 5,295	$ 652	$ 7,468	$ 833	$ 740
Sub-total	*$ 168,138*	*$ 101,853*	*$ 29,014*	*$ 28,230*	*$ 7,468*	*$ 833*	*$ 740*
Maintenance							
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 114,976	$ 82,192	$ 20,003	$ 12,780	$ -	$ -	$ -
CWNB	$ 398,885	$ 303,105	$ 65,211	$ 28,094	$ 121	$ 1,388	$ 966
Sub-total	*$ 513,861*	*$ 385,298*	*$ 85,214*	*$ 40,875*	*$ 121*	*$ 1,388*	*$ 966*
Total Operation, Maintenance and Billing	$ 681,999	$ 487,150	$ 114,228	$ 69,105	$ 7,588	$ 2,221	$ 1,706
Amortization Expense - Meters	$ 56,581	$ 28,654	$ 12,913	$ 15,014	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 10,159	$ 5,150	$ 2,316	$ 2,692	$ -	$ -	$ -
Admin and General	$ 612,286	$ 436,237	$ 102,771	$ 62,807	$ 6,926	$ 2,004	$ 1,542
Allocated PILs	$ 14,045	$ 7,113	$ 3,205	$ 3,727	$ -	$ -	$ -
Allocated Debt Return	$ 36,646	$ 18,558	$ 8,364	$ 9,724	$ -	$ -	$ -
Allocated Equity Return	$ 32,007	$ 16,209	$ 7,305	$ 8,493	$ -	$ -	$ -
Total	**$ 1,360,125**	**$ 936,211**	**$ 237,491**	**$ 164,782**	**$ 14,493**	**$ 4,058**	**$ 3,091**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 4,627,576	$ 3,547,390	$ 381,597	$ 46,971	$ 538,227	$ 60,063	$ 53,328
	SNCP	$ 1,036,000	$ 844,749	$ 35,322	$ 757	$ 128,169	$ 14,303	$ 12,699
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 2,613,562	$ 2,006,250	$ 215,815	$ 22,970	$ 304,398	$ 33,969	$ 30,160
	CWCS	$ 2,394,181	$ 2,191,293	$ 183,253	$ 19,634	$ -	$ -	$ -
	CWMC	$ 1,865,032	$ 944,496	$ 425,644	$ 494,892	$ -	$ -	$ -
	Sub-total	*$ 12,536,351*	*$ 9,534,178*	*$ 1,241,632*	*$ 585,224*	*$ 970,794*	*$ 108,335*	*$ 96,188*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (8,064,431)	$ (6,118,151)	$ (807,730)	$ (433,674)	$ (582,169)	$ (64,934)	$ (57,773)
	Customer Related Net Fixed Assets	$ 4,471,920	$ 3,416,027	$ 433,901	$ 151,551	$ 388,625	$ 43,401	$ 38,415
	Allocated General Plant Net Fixed Assets	$ 1,055,778	$ 808,054	$ 102,428	$ 35,764	$ 90,485	$ 10,107	$ 8,940
	Customer Related NFA Including General Plant	$ 5,527,698	$ 4,224,081	$ 536,329	$ 187,314	$ 479,111	$ 53,508	$ 47,355
	Misc Revenue							
	CWNB	$ (205,239)	$ (155,958)	$ (33,553)	$ (14,455)	$ (62)	$ (714)	$ (497)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (37,522)	$ (27,849)	$ (6,079)	$ (3,535)	$ (8)	$ (8)	$ (45)
	Sub-total	*$ (242,761)*	*$ (183,806)*	*$ (39,632)*	*$ (17,990)*	*$ (70)*	*$ (722)*	*$ (542)*
	Operating and Maintenance							
	1815-1855	$ 99,692	$ 79,442	$ 7,761	$ 1,683	$ 8,924	$ 995	$ 886
	1830 & 1835	$ 38,179	$ 29,945	$ 2,477	$ 257	$ 4,543	$ 507	$ 450
	1850	$ 14,899	$ 11,437	$ 1,230	$ 131	$ 1,735	$ 194	$ 172
	1840 & 1845	$ 617	$ 473	$ 51	$ 6	$ 72	$ 8	$ 7
	CWMC	$ 103,931	$ 52,633	$ 23,720	$ 27,579	$ -	$ -	$ -
	CCA	$ 64,207	$ 49,219	$ 5,295	$ 652	$ 7,468	$ 833	$ 740
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 8,181	$ 6,475	$ 473	$ 44	$ 982	$ 110	$ 97
	1835	$ 24,198	$ 18,786	$ 1,761	$ 200	$ 2,850	$ 318	$ 282
	1855	$ 99,606	$ 91,165	$ 7,624	$ 817	$ -	$ -	$ -
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ 3,756	$ 2,880	$ 310	$ 38	$ 437	$ 49	$ 43
	1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 457,266*	*$ 342,455*	*$ 50,701*	*$ 31,406*	*$ 27,012*	*$ 3,014*	*$ 2,678*
	Billing and Collection							
	CWNB	$ 424,977	$ 322,933	$ 69,477	$ 29,932	$ 129	$ 1,479	$ 1,029
	CWMR	$ 114,976	$ 82,192	$ 20,003	$ 12,780	$ -	$ -	$ -
	BDHA	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 559,953*	*$ 425,125*	*$ 89,480*	*$ 42,712*	*$ 129*	*$ 1,479*	*$ 1,029*
	Sub Total Operating, Maintenance and Biling	*$ 1,017,219*	*$ 767,580*	*$ 140,181*	*$ 74,118*	*$ 27,141*	*$ 4,493*	*$ 3,707*
	Amortization Expense - Customer Related	$ 398,669	$ 302,086	$ 39,354	$ 20,442	$ 30,383	$ 3,389	$ 3,015
	Amortization Expense - General Plant assigned to Meters	$ 69,266	$ 53,013	$ 6,720	$ 2,346	$ 5,936	$ 663	$ 587
	Admin and General	$ 913,017	$ 687,359	$ 126,121	$ 67,363	$ 24,771	$ 4,053	$ 3,350
	Allocated PILs	$ 95,840	$ 73,210	$ 9,299	$ 3,248	$ 8,329	$ 930	$ 823
	Allocated Debt Return	$ 250,071	$ 191,025	$ 24,264	$ 8,475	$ 21,732	$ 2,427	$ 2,148
	Allocated Equity Return	$ 218,416	$ 166,844	$ 21,192	$ 7,402	$ 18,981	$ 2,120	$ 1,876
	PLCC Adjustment for Line Transformer	$ 74,434	$ 66,516	$ 7,156	$ 762	$ -	$ -	$ -
	PLCC Adjustment for Primary Costs	$ 119,992	$ 107,391	$ 11,245	$ 1,356	$ -	$ -	$ -
	PLCC Adjustment for Secondary Costs	$ 59,544	$ 53,483	$ 5,413	$ 648	$ -	$ -	$ -

Total	**$**	**2,465,765**	**$**	**1,829,921**	**$**	**303,685**	**$**	**162,638**	**$**	**137,203**	**$**	**17,354**	**$**	**14,964**

Ontario

2010 COST ALLOCATION FILING
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
Friday, August 28, 2009
Sheet O2.1 Line Transformer Worksheet - Second Run

Line Transformers Demand Unit Cost for PLCC
Adjustment to Customer Related Cost
Allocation by rate classification

		1	2	3	4	5	6	7	8	9
Description	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Depreciation on Acct 1850 Line Transformers	$180,084	$64,948	$40,833	$74,303	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Line Transformers	$36,588	$13,215	$8,291	$15,082	$0	$0	$0	$0	$0	$0
Acct 5035 - Overhead Distribution Transformers- Operation	$2,490	$898	$565	$1,027	$0	$0	$0	$0	$0	$0
Acct 5055 - Underground Distribution Transformers - Operation	$486	$175	$110	$200	$0	$0	$0	$0	$0	$0
Acct 5160 - Maintenance of Line Transformers	$31,789	$11,465	$7,208	$13,116	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$64,888	$23,402	$14,713	$26,773	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Line Transformers	$31,357	$11,228	$7,092	$13,037	$0	$0	$0	$0	$0	$0
PILs on Line Transformers	$50,601	$18,250	$11,473	$20,878	$0	$0	$0	$0	$0	$0
Debt Return on Line Transformers	$132,031	$47,618	$29,937	$54,476	$0	$0	$0	$0	$0	$0
Equity Return on Line Transformers	$115,318	$41,590	$26,148	$47,580	$0	$0	$0	$0	$0	$0
Total	**$645,634**	**$232,789**	**$146,370**	**$266,474**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Line Tranformer NCP	155,953	56,245	35,361	64,346	0	0	0	0	0	0
PLCC Amount	19,968	16,071	1,729	184	0	0	0	1,678	121	186
Adjustment to Customer Related Cost for PLCC	**$74,434**	**$66,516**	**$7,156**	**$762**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$0	$0	$0	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	$0	$0	$0	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$0	$0	$0	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$0	$0	$0	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	**$11,676,198**	**$6,197,153**	**$1,965,155**	**$3,041,286**	**$0**	**$0**	**$0**	**$390,322**	**$43,523**	**$38,759**
Total Administration and General Expense	$1,307,693	$844,952	$209,428	$221,138	$0	$0	$0	$24,771	$4,053	$3,350
Total O&M	**$1,454,997**	**$943,566**	**$232,777**	**$243,314**	**$0**	**$0**	**$0**	**$27,141**	**$4,493**	**$3,707**
Line Transformer Rate Base										
Acct 1850 - Line Transformers - Gross Assets	$6,098,311	$2,199,391	$1,382,751	$2,516,170	$0	$0	$0	$0	$0	$0
Line Transformers - Accumulated Depreciation	($3,737,244)	($1,347,858)	($847,395)	($1,541,991)	$0	$0	$0	$0	$0	$0
Line Transformers - Net Fixed Assets	$2,361,067	$851,532	$535,356	$974,179	$0	$0	$0	$0	$0	$0
General Plant Assigned to Line Transformers - NFA	$557,698	$201,428	$126,378	$229,892	$0	$0	$0	$0	$0	$0
Line Transformer Net Fixed Assets Including General Plant	$2,918,765	$1,052,961	$661,734	$1,204,071	$0	$0	$0	$0	$0	$0
General Expenses										
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$101,571	$39,731	$21,761	$40,080	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$83,571	$32,690	$17,904	$32,977	$0	$0	$0	$0	$0	$0
Total	$185,142	$72,420	$39,665	$73,057	$0	$0	$0	$0	$0	$0
Acct 1850 - Line Transformers - Gross Assets	$6,098,311	$2,199,391	$1,382,751	$2,516,170	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$17,399,961	$6,806,182	$3,727,764	$6,866,016	$0	$0	$0	$0	$0	$0

2010 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet O2.2 Primary Cost PLCC Adjustment Worksheet - Second Run

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

		1	2	3	4	5	6	7	8	9
Description	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$46,674	$15,774	$9,917	$20,984	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1835-4 Primary Overhead Conductors	$67,339	$22,758	$14,308	$30,274	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1840-4 Primary Underground Conduit	$72,996	$24,669	$15,509	$32,817	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1845-4 Primary Underground Conductors	$84,416	$28,529	$17,936	$37,952	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Primary C&P	$55,496	$18,783	$11,785	$24,928	$0	$0	$0	$0	$0	$0
Primary C&P Operations and Maintenance	$111,689	$43,096	$23,740	$44,853	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$91,444	$30,904	$19,429	$41,111	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Primary C&P	$100,716	$38,592	$21,359	$40,765	$0	$0	$0	$0	$0	$0
PILs on Primary C&P	$76,754	$25,939	$16,308	$34,507	$0	$0	$0	$0	$0	$0
Debt Return on Primary C&P	$200,272	$67,683	$42,552	$90,038	$0	$0	$0	$0	$0	$0
Equity Return on Primary C&P	$174,921	$59,115	$37,166	$78,640	$0	$0	$0	$0	$0	$0
Total	**$1,082,717**	**$375,841**	**$230,009**	**$476,868**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Primary NCP	166,429	56,245	35,361	74,822	0	0	0	0	0	0
PLCC Amount	19,997	16,071	1,729	213	0	0	0	1,678	121	186
Adjustment to Customer Related Cost for PLCC	**$119,992**	**$107,391**	**$11,245**	**$1,356**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$0	$0	$0	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	$0	$0	$0	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$0	$0	$0	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$0	$0	$0	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	**$11,676,198**	**$6,197,153**	**$1,965,155**	**$3,041,286**	**$0**	**$0**	**$0**	**$390,322**	**$43,523**	**$38,759**
Total Administration and General Expense	**$1,307,693**	**$844,952**	**$209,428**	**$221,138**	**$0**	**$0**	**$0**	**$24,771**	**$4,053**	**$3,350**
Total O&M	**$1,454,997**	**$943,566**	**$232,777**	**$243,314**	**$0**	**$0**	**$0**	**$27,141**	**$4,493**	**$3,707**
Primary Conductors and Poles Gross Assets										
Acct 1830-4 Primary Poles, Towers & Fixtures	$1,368,122	$462,362	$290,686	$615,075	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	$2,000,145	$675,956	$424,972	$899,217	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	$2,482,587	$838,999	$527,476	$1,116,111	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	$2,743,217	$927,080	$582,853	$1,233,284	$0	$0	$0	$0	$0	$0
Subtotal	*$8,594,071*	*$2,904,398*	*$1,825,986*	*$3,863,687*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*

Primary Conductors and Poles Accumulated Depreciation										
Acct 1830-4 Primary Poles, Towers & Fixtures	($917,155)	($309,956)	($194,868)	($412,331)	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	($1,037,548)	($350,643)	($220,448)	($466,457)	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	($1,441,423)	($487,134)	($306,260)	($648,029)	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	($1,616,552)	($546,320)	($343,470)	($726,763)	$0	$0	$0	$0	$0	$0
Subtotal	***($5,012,678)***	***($1,694,053)***	***($1,065,046)***	***($2,253,579)***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Primary Conductor & Pools - Net Fixed Assets	$3,581,392	$1,210,345	$760,940	$1,610,107	$0	$0	$0	$0	$0	$0
General Plant Assigned to Primary C&P - NFA	$845,896	$286,305	$179,630	$379,962	$0	$0	$0	$0	$0	$0
Primary C&P Net Fixed Assets Including General Plant	$4,427,288	$1,496,649	$940,570	$1,990,069	$0	$0	$0	$0	$0	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-5 Secondary Poles, Towers & Fixtures	$1,423,964	$1,063,961	$260,917	$99,086	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	$500,036	$373,618	$91,623	$34,795	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$1,924,000***	***$1,437,580***	***$352,540***	***$133,880***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Operations and Maintenance										
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$2,442	$1,189	$493	$761	$0	$0	$0	$0	$0	$0
Acct 5025 Overhead Distribution Lines & Feeders - Other	$702	$342	$142	$219	$0	$0	$0	$0	$0	$0
Acct 5040 Underground Distribution Lines & Feeders - Labour	$970	$328	$206	$436	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$176	$59	$37	$79	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$15,193	$8,306	$3,002	$3,886	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$44,938	$18,865	$9,285	$16,788	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$67,760	$32,981	$13,677	$21,102	$0	$0	$0	$0	$0	$0
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$6,976	$2,358	$1,482	$3,136	$0	$0	$0	$0	$0	$0
Total	**$139,157**	**$64,426**	**$28,324**	**$46,407**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Expenses										
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$101,571	$39,731	$21,761	$40,080	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$83,571	$32,690	$17,904	$32,977	$0	$0	$0	$0	$0	$0
Total	**$185,142**	**$72,420**	**$39,665**	**$73,057**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Primary Conductors and Poles Gross Assets	$8,594,071	$2,904,398	$1,825,986	$3,863,687	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$17,399,961	$6,806,182	$3,727,764	$6,866,016	$0	$0	$0	$0	$0	$0

Ontario

2010 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
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Friday, August 28, 2009
Sheet O2.3 Secondary Cost PLCC Adjustment Worksheet - Second Run

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

		1	2	3	4	5	6	7	8	9
Description	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$48,579	$36,298	$8,901	$3,380	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$25,900	$19,970	$3,394	$1,178	$0	$0	$0	$1,121	$125	$111
Depreciation on Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Secondary C&P	$11,013	$8,233	$2,015	$765	$0	$0	$0	$0	$0	$0
Secondary C&P Operations and Maintenance	$27,469	$21,331	$4,583	$1,554	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$20,472	$15,296	$3,751	$1,425	$0	$0	$0	$0	$0	$0
Admin and General Assigned to Primary C&P	$24,638	$19,102	$4,124	$1,413	$0	$0	$0	$0	$0	$0
PILs on Secondary C&P	$15,217	$11,370	$2,788	$1,059	$0	$0	$0	$0	$0	$0
Debt Return on Secondary C&P	$39,705	$29,667	$7,275	$2,763	$0	$0	$0	$0	$0	$0
Equity Return on Secondary C&P	$34,679	$25,911	$6,354	$2,413	$0	$0	$0	$0	$0	$0
Total	**$247,670**	**$187,177**	**$43,186**	**$15,949**	**$0**	**$0**	**$0**	**$1,121**	**$125**	**$111**
Secondary NCP	75,276	56,245	13,793	5,238	0	0	0	0	0	0
PLCC Amount	19,997	16,071	1,729	213	0	0	0	1,678	121	186
Adjustment to Customer Related Cost for PLCC	**$59,544**	**$53,483**	**$5,413**	**$648**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$0	$0	$0	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	$0	$0	$0	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$0	$0	$0	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$0	$0	$0	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	$11,676,198	$6,197,153	$1,965,155	$3,041,286	$0	$0	$0	$390,322	$43,523	$38,759
Total Administration and General Expense	$1,307,693	$844,952	$209,428	$221,138	$0	$0	$0	$24,771	$4,053	$3,350
Total O&M	$1,454,997	$943,566	$232,777	$243,314	$0	$0	$0	$27,141	$4,493	$3,707
Secondary Conductors and Poles Gross Plant										
Acct 1830-5 Secondary Poles, Towers & Fixtures	$1,423,964	$1,063,961	$260,917	$99,086	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	$500,036	$373,618	$91,623	$34,795	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$1,924,000***	***$1,437,580***	***$352,540***	***$133,880***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***

Secondary Conductors and Poles Accumulated Depreciation										
Acct 1830-5 Secondary Poles, Towers & Fixtures	($954,590)	($713,253)	($174,912)	($66,425)	$0	$0	$0	$0	$0	$0
Acct 1835-5 Secondary Overhead Conductors	($259,387)	($193,810)	($47,528)	($18,049)	$0	$0	$0	$0	$0	$0
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***($1,213,977)***	***($907,063)***	***($222,440)***	***($84,474)***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Secondary Conductor & Pools - Net Fixed Assets	$710,023	$530,517	$130,100	$49,407	$0	$0	$0	$0	$0	$0
General Plant Assigned to Secondary C&P - NFA	$167,864	$125,493	$30,712	$11,659	$0	$0	$0	$0	$0	$0
Secondary C&P Net Fixed Assets Including General Plant	$877,887	$656,010	$160,811	$61,066	$0	$0	$0	$0	$0	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$1,368,122	$462,362	$290,686	$615,075	$0	$0	$0	$0	$0	$0
Acct 1835-4 Primary Overhead Conductors	$2,000,145	$675,956	$424,972	$899,217	$0	$0	$0	$0	$0	$0
Acct 1840-4 Primary Underground Conduit	$2,482,587	$838,999	$527,476	$1,116,111	$0	$0	$0	$0	$0	$0
Acct 1845-4 Primary Underground Conductors	$2,743,217	$927,080	$582,853	$1,233,284	$0	$0	$0	$0	$0	$0
Subtotal	***$8,594,071***	***$2,904,398***	***$1,825,986***	***$3,863,687***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Operations and Maintenance										
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$2,442	$1,189	$493	$761	$0	$0	$0	$0	$0	$0
Acct 5025 Overhead Distribution Lines & Feeders - Other	$702	$342	$142	$219	$0	$0	$0	$0	$0	$0
Acct 5040 Underground Distribution Lines & Feeders - Labour	$970	$328	$206	$436	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$176	$59	$37	$79	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$15,193	$8,306	$3,002	$3,886	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$44,938	$18,865	$9,285	$16,788	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$67,760	$32,981	$13,677	$21,102	$0	$0	$0	$0	$0	$0
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$6,976	$2,358	$1,482	$3,136	$0	$0	$0	$0	$0	$0
Total	**$139,157**	**$64,426**	**$28,324**	**$46,407**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Expenses										
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$101,571	$39,731	$21,761	$40,080	$0	$0	$0	$0	$0	$0
Acct 5105 - Maintenance Supervision and Engineering	$83,571	$32,690	$17,904	$32,977	$0	$0	$0	$0	$0	$0
Total	**$185,142**	**$72,420**	**$39,665**	**$73,057**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Secondary Conductors and Poles Gross Assets	$1,924,000	$1,437,580	$352,540	$133,880	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$17,399,961	$6,806,182	$3,727,764	$6,866,016	$0	$0	$0	$0	$0	$0

2010 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
Friday, August 28, 2009

Sheet O3.1 Line Transformers Unit Cost Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	7	8	9
Description	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Depreciation on Acct 1850 Line Transformers	$257,263	$124,193	$47,206	$74,981	$8,989	$1,003	$891
Depreciation on General Plant Assigned to Line Transformers	$52,254	$25,269	$9,585	$15,220	$1,800	$201	$178
Acct 5035 - Overhead Distribution Transformers- Operation	$3,558	$1,717	$653	$1,037	$124	$14	$12
Acct 5055 - Underground Distribution Transformers - Operation	$694	$335	$127	$202	$24	$3	$2
Acct 5160 - Maintenance of Line Transformers	$45,413	$21,923	$8,333	$13,236	$1,587	$177	$157
Allocation of General Expenses	$88,193	$41,311	$16,578	$26,921	$2,794	$312	$277
Admin and General Assigned to Line Transformers	$44,739	$21,470	$8,199	$13,156	$1,584	$175	$155
PILs on Line Transformers	$72,287	$34,896	$13,264	$21,069	$2,526	$282	$250
Debt Return on Line Transformers	$188,616	$91,054	$34,610	$54,974	$6,590	$735	$653
Equity Return on Line Transformers	$164,740	$79,528	$30,229	$48,015	$5,756	$642	$570
Less: Transformer Ownership Allowance Credit	$0	$0	$0	$0	$0	$0	$0
Total	**$917,757**	**$441,698**	**$168,783**	**$268,810**	**$31,775**	**$3,544**	**$3,147**
Billed kW without Line Transformer Allowance		0	0	142,959	5,102	360	0
Billed kWh without Line Transformer Allowance		84,928,233	38,954,924	122,840,423	1,798,732	129,899	376,928
Line Transformation Unit Cost ($/kW)		**$0.0000**	**$0.0000**	**$1.8803**	**$6.2280**	**$9.8501**	**$0.0000**
Line Transformation Unit Cost ($/kWh)		**$0.0052**	**$0.0043**	**$0.0022**	**$0.0177**	**$0.0273**	**$0.0083**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	$11,676,198	$6,197,153	$1,965,155	$3,041,286	$390,322	$43,523	$38,759
Total Administration and General Expense	$1,307,693	$844,952	$209,428	$221,138	$24,771	$4,053	$3,350
Total O&M	$1,454,997	$943,566	$232,777	$243,314	$27,141	$4,493	$3,707
Line Transformer Rate Base							
Acct 1850 - Line Transformers - Gross Assets	$8,711,874	$4,205,641	$1,598,566	$2,539,140	$304,398	$33,969	$30,160
Line Transformers - Accumulated Depreciation	($5,338,920)	($2,577,354)	($979,653)	($1,556,068)	($186,545)	($20,817)	($18,483)
Line Transformers - Net Fixed Assets	$3,372,953	$1,628,287	$618,912	$983,072	$117,853	$13,152	$11,677
General Plant Assigned to Line Transformers - NFA	$796,481	$385,168	$146,102	$231,991	$27,440	$3,063	$2,717
Line Transformer Net Fixed Assets Including General Plant	$4,169,435	$2,013,455	$765,015	$1,215,063	$145,293	$16,214	$14,394
General Expenses							
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$156,263	$83,314	$26,019	$41,003	$4,896	$546	$486
Acct 5105 - Maintenance Supervision and Engineering	$128,570	$68,549	$21,408	$33,737	$4,028	$449	$400
Total	**$284,833**	**$151,862**	**$47,426**	**$74,740**	**$8,924**	**$995**	**$886**
Acct 1850 - Line Transformers - Gross Assets	$8,711,874	$4,205,641	$1,598,566	$2,539,140	$304,398	$33,969	$30,160
Acct 1815 - 1855	$28,259,763	$15,460,143	$4,573,236	$7,049,322	$972,156	$108,433	$96,473

2010 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
Friday, August 28, 2009
Sheet O3.2 Substation Transformers Unit Cost Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

Description		1	2	3	7	8	9
	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Depreciation on Acct 1820-2 Distribution Station Equipment	$21,904	$7,402	$4,654	$9,847	$0	$0	$0
Depreciation on Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1805-2 Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1806-2 Land Rights Station <50 kV	$1,353	$500	$240	$601	$9	$1	$2
Depreciation on Acct 1808-2 Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1810-2 Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Substation Transformers	($6,512)	($2,178)	($1,411)	($2,929)	$5	$0	$1
Acct 5012 - Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0
Acct 5016 - Distributon Station Equipment - Labour	$1,013	$342	$215	$456	$0	$0	$0
Acct 5017 - Distributon Station Equipment - Other	$66,355	$22,425	$14,098	$29,832	$0	$0	$0
Acct 5114 - Maintenance of Distribution Station Equipment	$11,345	$3,834	$2,411	$5,101	$0	$0	$0
Allocation of General Expenses	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to SubstationTransformers	$71,031	$23,821	$15,047	$32,162	$0	$0	$0
PILs on SubstationTransformers	($9,007)	($3,008)	($1,953)	($4,055)	$7	$1	$1
Debt Return on Substation Transformers	($23,501)	($7,849)	($5,095)	($10,581)	$19	$1	$3
Equity Return on Substation Transformers	($20,526)	($6,855)	($4,450)	($9,241)	$16	$1	$3
Total	**$113,453**	**$38,435**	**$23,756**	**$51,192**	**$56**	**$4**	**$10**
Billed kW without Substation Transformer Allowance		0	0	293,178	5,102	360	0
Billed kWh without Substation Transformer Allowance		84,928,233	38,954,924	122,840,423	1,798,732	129,899	376,928
Substation Transformation Unit Cost ($/kW)		**$0.0000**	**$0.0000**	**$0.1746**	**$0.0110**	**$0.0113**	**$0.0000**
Substation Transformation Unit Cost ($/kWh)		**$0.0005**	**$0.0006**	**$0.0004**	**$0.0000**	**$0.0000**	**$0.0000**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	$11,676,198	$6,197,153	$1,965,155	$3,041,286	$390,322	$43,523	$38,759
Total Administration and General Expense	$1,307,693	$844,952	$209,428	$221,138	$24,771	$4,053	$3,350
Total O&M	$1,454,997	$943,566	$232,777	$243,314	$27,141	$4,493	$3,707
Substation Transformer Rate Base Gross Plant							
Acct 1820-2 Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0
Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Acct 1805-2 Land Station <50 kV	$29,126	$10,773	$5,176	$12,944	$187	$13	$33
Acct 1806-2 Land Rights Station <50 kV	$33,817	$12,508	$6,009	$15,029	$217	$16	$38
Acct 1808-2 Buildings and Fixtures < 50 KV	$15,296	$5,658	$2,718	$6,798	$98	$7	$17
Acct 1810-2 Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$78,239***	***$28,938***	***$13,903***	***$34,772***	***$502***	***$36***	***$88***
Substation Transformers - Accumulated Depreciation							
Acct 1820-2 Distribution Station Equipment	($472,576)	($159,709)	($100,408)	($212,459)	$0	$0	$0
Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Acct 1805-2 Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0
Acct 1806-2 Land Rights Station <50 kV	($10,634)	($3,933)	($1,890)	($4,726)	($68)	($5)	($12)
Acct 1808-2 Buildings and Fixtures < 50 KV	($15,296)	($5,658)	($2,718)	($6,798)	($98)	($7)	($17)
Acct 1810-2 Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
Subtotal	***($498,505)***	***($169,299)***	***($105,016)***	***($223,983)***	***($166)***	***($12)***	***($29)***
Substation Transformers - Net Fixed Assets	($420,266)	($140,361)	($91,113)	($189,211)	$336	$24	$59
General Plant Assigned to SubstationTransformers - NFA	($99,264)	($33,202)	($21,508)	($44,651)	$78	$6	$14
Substation Transformer NFA Including General Plant	($519,530)	($173,563)	($112,621)	($233,862)	$414	$30	$73
General Expenses							
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$156,263	$83,314	$26,019	$41,003	$4,896	$546	$486
Acct 5105 - Maintenance Supervision and Engineering	$128,570	$68,549	$21,408	$33,737	$4,028	$449	$400
Total	$284,833	$151,862	$47,426	$74,740	$8,924	$995	$886
Acct 1820-2 Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0
Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0	$0	$0
Acct 1815 - 1855	$28,259,763	$15,460,143	$4,573,236	$7,049,322	$972,156	$108,433	$96,473

Sheet O3.3 Primary Conductors and Poles Cost Pool Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

Description		1	2	3	7	8	9
	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$71,806	$35,039	$11,989	$21,239	$2,923	$326	$290
Depreciation on Acct 1835-4 Primary Overhead Conductors	$103,599	$50,553	$17,298	$30,642	$4,217	$471	$418
Depreciation on Acct 1840-4 Primary Underground Conduit	$112,301	$54,800	$18,751	$33,216	$4,572	$510	$453
Depreciation on Acct 1845-4 Primary Underground Conductors	$129,871	$63,374	$21,684	$38,413	$5,287	$590	$524
Depreciation on General Plant Assigned to Primary C&P	$85,352	$41,725	$14,248	$25,231	$3,426	$382	$339
Primary C&P Operations and Maintenance	$173,329	$90,847	$28,405	$45,389	$7,176	$801	$711
Allocation of General Expenses	$133,712	$63,375	$22,893	$41,462	$4,941	$551	$490
Admin and General Assigned to Primary C&P	$156,075	$81,352	$25,556	$41,252	$6,549	$722	$643
PILs on Primary C&P	$118,083	$57,621	$19,716	$34,926	$4,807	$536	$476
Debt Return on Primary C&P	$308,111	$150,349	$51,445	$91,132	$12,543	$1,400	$1,243
Equity Return on Primary C&P	$269,109	$131,318	$44,932	$79,596	$10,955	$1,223	$1,085
Total	**$1,661,349**	**$820,354**	**$276,917**	**$482,500**	**$67,395**	**$7,513**	**$6,671**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	$11,676,198	$6,197,153	$1,965,155	$3,041,286	$390,322	$43,523	$38,759
Total Administration and General Expense	$1,307,693	$844,952	$209,428	$221,138	$24,771	$4,053	$3,350
Total O&M	$1,454,997	$943,566	$232,777	$243,314	$27,141	$4,493	$3,707
Primary Conductors and Poles Gross Assets							
Acct 1830-4 Primary Poles, Towers & Fixtures	$2,104,803	$1,027,084	$351,433	$622,552	$85,682	$9,562	$8,490
Acct 1835-4 Primary Overhead Conductors	$3,077,146	$1,501,560	$513,783	$910,149	$125,265	$13,979	$12,411
Acct 1840-4 Primary Underground Conduit	$3,819,364	$1,863,741	$637,709	$1,129,680	$155,479	$17,351	$15,405
Acct 1845-4 Primary Underground Conductors	$4,220,334	$2,059,403	$704,658	$1,248,277	$171,801	$19,172	$17,022
Subtotal	**$13,221,647**	**$6,451,787**	**$2,207,584**	**$3,910,658**	**$538,227**	**$60,063**	**$53,328**
Primary Conductors and Poles Accumulated Depreciation							
Acct 1830-4 Primary Poles, Towers & Fixtures	($1,411,007)	($688,531)	($235,592)	($417,343)	($57,439)	($6,410)	($5,691)
Acct 1835-4 Primary Overhead Conductors	($1,596,228)	($778,914)	($266,518)	($472,127)	($64,979)	($7,251)	($6,438)
Acct 1840-4 Primary Underground Conduit	($2,217,574)	($1,082,113)	($370,263)	($655,907)	($90,273)	($10,074)	($8,944)
Acct 1845-4 Primary Underground Conductors	($2,487,003)	($1,213,587)	($415,248)	($735,598)	($101,241)	($11,298)	($10,031)
Subtotal	**($7,711,813)**	**($3,763,145)**	**($1,287,621)**	**($2,280,976)**	**($313,933)**	**($35,033)**	**($31,105)**

Primary Conductor & Pools - Net Fixed Assets	$5,509,834	$2,688,642	$919,962	$1,629,682	$224,294	$25,030	$22,223
General Plant Assigned to Primary C&P - NFA	$1,300,967	$635,993	$217,169	$384,581	$52,223	$5,829	$5,172
Primary C&P Net Fixed Assets Including General Plant	$6,810,801	$3,324,635	$1,137,131	$2,014,263	$276,518	$30,859	$27,395
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Subtotal	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Acct 1830-5 Secondary Poles, Towers & Fixtures	$2,190,713	$1,689,165	$287,059	$99,646	$94,859	$10,586	$9,399
Acct 1835-5 Secondary Overhead Conductors	$769,286	$593,164	$100,803	$34,991	$33,310	$3,717	$3,300
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Subtotal	**$2,960,000**	**$2,282,329**	**$387,862**	**$134,637**	**$128,169**	**$14,303**	**$12,699**
Operations and Maintenance							
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$3,758	$2,220	$578	$769	$157	$17	$16
Acct 5025 Overhead Distribution Lines & Feeders - Other	$1,080	$638	$166	$221	$45	$5	$4
Acct 5040 Underground Distribution Lines & Feeders - Labour	$1,492	$728	$249	$441	$61	$7	$6
Acct 5045 Underground Distribution Lines & Feeders - Other	$270	$132	$45	$80	$11	$1	$1
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$23,374	$14,781	$3,474	$3,930	$982	$110	$97
Acct 5125 Maintenance of Overhead Conductors & Devices	$69,136	$37,651	$11,047	$16,988	$2,850	$318	$282
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$104,245	$61,597	$16,044	$21,348	$4,342	$485	$430
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$10,732	$5,237	$1,792	$3,174	$437	$49	$43
Total	**$214,088**	**$122,984**	**$33,396**	**$46,952**	**$8,885**	**$991**	**$880**
General Expenses							
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$156,263	$83,314	$26,019	$41,003	$4,896	$546	$486
Acct 5105 - Maintenance Supervision and Engineering	$128,570	$68,549	$21,408	$33,737	$4,028	$449	$400
Total	**$284,833**	**$151,862**	**$47,426**	**$74,740**	**$8,924**	**$995**	**$886**
Primary Conductors and Poles Gross Assets	$13,221,647	$6,451,787	$2,207,584	$3,910,658	$538,227	$60,063	$53,328
Acct 1815 - 1855	$28,259,763	$15,460,143	$4,573,236	$7,049,322	$972,156	$108,433	$96,473

Grouping of Operation and Maintenance	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
1830	$ 23,374	$ 14,781	$ 3,474	$ 3,930	$ 982	$ 110	$ 97
1835	$ 69,136	$ 37,651	$ 11,047	$ 16,988	$ 2,850	$ 318	$ 282
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 10,732	$ 5,237	$ 1,792	$ 3,174	$ 437	$ 49	$ 43
1830 & 1835	$ 109,083	$ 64,456	$ 16,788	$ 22,338	$ 4,543	$ 507	$ 450
1840 & 1845	$ 1,762	$ 860	$ 294	$ 521	$ 72	$ 8	$ 7
Total	**$ 214,088**	**$ 122,984**	**$ 33,396**	**$ 46,952**	**$ 8,885**	**$ 991**	**$ 880**

2010 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
Friday, August 28, 2009
Sheet O3.4 Secondary Cost Pool Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	7	8	9
Description	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$74,737	$57,627	$9,793	$3,399	$3,236	$361	$321
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$25,900	$19,970	$3,394	$1,178	$1,121	$125	$111
Depreciation on Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Secondary C&P	$16,932	$13,071	$2,217	$769	$723	$81	$72
Secondary C&P Operations and Maintenance	$40,759	$32,137	$4,991	$1,563	$1,709	$191	$169
Allocation of General Expenses	$29,293	$22,419	$4,022	$1,427	$1,177	$131	$117
Admin and General Assigned to Primary C&P	$36,573	$28,778	$4,490	$1,420	$1,560	$172	$153
PILs on Secondary C&P	$23,410	$18,051	$3,068	$1,065	$1,014	$113	$100
Debt Return on Secondary C&P	$61,084	$47,099	$8,004	$2,778	$2,645	$295	$262
Equity Return on Secondary C&P	$53,352	$41,137	$6,991	$2,427	$2,310	$258	$229
Total	**$362,041**	**$280,290**	**$46,969**	**$16,027**	**$15,494**	**$1,727**	**$1,534**
General Plant - Gross Assets	$5,433,191	$2,888,295	$914,017	$1,414,075	$179,061	$19,970	$17,772
General Plant - Accumulated Depreciation	($2,675,631)	($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)
General Plant - Net Fixed Assets	$2,757,560	$1,465,924	$463,900	$717,699	$90,881	$10,136	$9,020
General Plant - Depreciation	$180,913	$96,174	$30,435	$47,086	$5,962	$665	$592
Total Net Fixed Assets Excluding General Plant	**$11,676,198**	**$6,197,153**	**$1,965,155**	**$3,041,286**	**$390,322**	**$43,523**	**$38,759**
Total Administration and General Expense	**$1,307,693**	**$844,952**	**$209,428**	**$221,138**	**$24,771**	**$4,053**	**$3,350**
Total O&M	**$1,454,997**	**$943,566**	**$232,777**	**$243,314**	**$27,141**	**$4,493**	**$3,707**
<u>Secondary Conductors and Poles Gross Plant</u>							
Acct 1830-5 Secondary Poles, Towers & Fixtures	$2,190,713	$1,689,165	$287,059	$99,646	$94,859	$10,586	$9,399
Acct 1835-5 Secondary Overhead Conductors	$769,286	$593,164	$100,803	$34,991	$33,310	$3,717	$3,300
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$2,960,000***	***$2,282,329***	***$387,862***	***$134,637***	***$128,169***	***$14,303***	***$12,699***
<u>Secondary Conductors and Poles Accumulated Depreciation</u>							
Acct 1830-5 Secondary Poles, Towers & Fixtures	($1,468,599)	($1,132,374)	($192,437)	($66,800)	($63,591)	($7,096)	($6,301)
Acct 1835-5 Secondary Overhead Conductors	($399,057)	($307,696)	($52,290)	($18,151)	($17,279)	($1,928)	($1,712)
Acct 1840-5 Secondary Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 1845-5 Secondary Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Subtotal	***($1,867,656)***	***($1,440,070)***	***($244,727)***	***($84,951)***	***($80,870)***	***($9,025)***	***($8,013)***

Secondary Conductor & Pools - Net Fixed Assets	$1,092,343	$842,259	$143,135	$49,686	$47,299	$5,278	$4,686
General Plant Assigned to Secondary C&P - NFA	$258,081	$199,235	$33,789	$11,725	$11,013	$1,229	$1,091
Secondary C&P Net Fixed Assets Including General Plant	$1,350,424	$1,041,494	$176,923	$61,411	$58,312	$6,507	$5,777
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$2,104,803	$1,027,084	$351,433	$622,552	$85,682	$9,562	$8,490
Acct 1835-4 Primary Overhead Conductors	$3,077,146	$1,501,560	$513,783	$910,149	$125,265	$13,979	$12,411
Acct 1840-4 Primary Underground Conduit	$3,819,364	$1,863,741	$637,709	$1,129,680	$155,479	$17,351	$15,405
Acct 1845-4 Primary Underground Conductors	$4,220,334	$2,059,403	$704,658	$1,248,277	$171,801	$19,172	$17,022
Subtotal	***$13,221,647***	***$6,451,787***	***$2,207,584***	***$3,910,658***	***$538,227***	***$60,063***	***$53,328***
Operations and Maintenance							
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$3,758	$2,220	$578	$769	$157	$17	$16
Acct 5025 Overhead Distribution Lines & Feeders - Other	$1,080	$638	$166	$221	$45	$5	$4
Acct 5040 Underground Distribution Lines & Feeders - Labour	$1,492	$728	$249	$441	$61	$7	$6
Acct 5045 Underground Distribution Lines & Feeders - Other	$270	$132	$45	$80	$11	$1	$1
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$23,374	$14,781	$3,474	$3,930	$982	$110	$97
Acct 5125 Maintenance of Overhead Conductors & Devices	$69,136	$37,651	$11,047	$16,988	$2,850	$318	$282
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$104,245	$61,597	$16,044	$21,348	$4,342	$485	$430
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$10,732	$5,237	$1,792	$3,174	$437	$49	$43
Total	**$214,088**	**$122,984**	**$33,396**	**$46,952**	**$8,885**	**$991**	**$880**
General Expenses							
Acct 5005 - Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0
Acct 5010 - Load Dispatching	$0	$0	$0	$0	$0	$0	$0
Acct 5085 - Miscellaneous Distribution Expense	$156,263	$83,314	$26,019	$41,003	$4,896	$546	$486
Acct 5105 - Maintenance Supervision and Engineering	$128,570	$68,549	$21,408	$33,737	$4,028	$449	$400
Total	**$284,833**	**$151,862**	**$47,426**	**$74,740**	**$8,924**	**$995**	**$886**
Secondary Conductors and Poles Gross Assets	$2,960,000	$2,282,329	$387,862	$134,637	$128,169	$14,303	$12,699
Acct 1815 - 1855	$28,259,763	$15,460,143	$4,573,236	$7,049,322	$972,156	$108,433	$96,473

Grouping of Operation and Maintenance

	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
1830	$ 23,374	$ 14,781	$ 3,474	$ 3,930	$ 982	$ 110	$ 97
1835	$ 69,136	$ 37,651	$ 11,047	$ 16,988	$ 2,850	$ 318	$ 282
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 10,732	$ 5,237	$ 1,792	$ 3,174	$ 437	$ 49	$ 43
1830 & 1835	$ 109,083	$ 64,456	$ 16,788	$ 22,338	$ 4,543	$ 507	$ 450
1840 & 1845	$ 1,762	$ 860	$ 294	$ 521	$ 72	$ 8	$ 7
Total	**$ 214,088**	**$ 122,984**	**$ 33,396**	**$ 46,952**	**$ 8,885**	**$ 991**	**$ 880**

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2010 COST ALLOCATION INFORMATION FI
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
Friday, August 28, 2009
Sheet O3.5 USL Metering Credit Wor

ALLOCATION BY RATE CLASSIFICATION

Description	GS <50
Depreciation on Acct 1860 Metering	$12,913
Depreciation on General Plant Assigned to Metering	$2,316
Acct 5065 - Meter expense	$23,720
Acct 5070 & 5075 - Customer Premises	$5,295
Acct 5175 - Meter Maintenance	$0
Acct 5310 - Meter Reading	$20,003
Admin and General Assigned to Metering	$44,101
PILs on Metering	$3,205
Debt Return on Metering	$8,364
Equity Return on Metering	$7,305
Total	$127,221
Number of Customers	1,081
Metering Unit Cost ($/Customer/Month)	**$9.81**
General Plant - Gross Assets	$914,017
General Plant - Accumulated Depreciation	($450,117)
General Plant - Net Fixed Assets	$463,900
General Plant - Depreciation	$30,435
Total Net Fixed Assets Excluding General Plant	$1,965,155
Total Administration and General Expense	$209,428
Total O&M	$232,777
Metering Rate Base	
Acct 1860 - Metering - Gross Assets	$425,644
Metering - Accumulated Depreciation	($276,083)
Metering - Net Fixed Assets	$149,561
General Plant Assigned to Metering - NFA	$35,306
Metering Net Fixed Assets Including General Plant	$184,867

2010 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet O4 Summary of Allocators by Class & Accounts - Second Run

ALLOCATION BY RATE CLASSIFICATION

				1	2	3	7	8	9
USoA Account #	**Accounts**	**O1 Grouping**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
1565	Conservation and Demand Management Expenditures and Recoveries	dp	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	gp	$0	$0	$0	$0	$0	$0	$0
1805	Land	dp	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	dp	$29,126	$10,773	$5,176	$12,944	$187	$13	$33
1806	Land Rights	dp	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	dp	$33,817	$12,508	$6,009	$15,029	$217	$16	$38
1808	Buildings and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	dp	$15,296	$5,658	$2,718	$6,798	$98	$7	$17
1810	Leasehold Improvements	dp	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	dp	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	dp	$783,580	$264,814	$166,488	$352,278	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	dp	$188,483	$64,280	$29,484	$92,974	$1,361	$98	$285
1825	Storage Battery Equipment	dp	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	dp	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	dp	$2,104,803	$1,027,084	$351,433	$622,552	$85,682	$9,562	$8,490
1830-5	Poles, Towers and Fixtures - Secondary	dp	$2,190,713	$1,689,165	$287,059	$99,646	$94,859	$10,586	$9,399
1835	Overhead Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	dp	$3,077,146	$1,501,560	$513,783	$910,149	$125,265	$13,979	$12,411
1835-5	Overhead Conductors and Devices - Secondary	dp	$769,286	$593,164	$100,803	$34,991	$33,310	$3,717	$3,300
1840	Underground Conduit	dp	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	dp	$3,819,364	$1,863,741	$637,709	$1,129,680	$155,479	$17,351	$15,405
1840-5	Underground Conduit - Secondary	dp	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	dp	$4,220,334	$2,059,403	$704,658	$1,248,277	$171,801	$19,172	$17,022
1845-5	Underground Conductors and Devices - Secondary	dp	$0	$0	$0	$0	$0	$0	$0

1850	Line Transformers	dp	$8,711,874	$4,205,641	$1,598,566	$2,539,140	$304,398	$33,969	$30,160
1855	Services	dp	$2,394,181	$2,191,293	$183,253	$19,634	$0	$0	$0
1860	Meters	dp	$1,865,032	$944,496	$425,644	$494,892	$0	$0	$0
1905	Land	gp	$144,400	$76,764	$24,292	$37,583	$4,759	$531	$472
1906	Land Rights	gp	$4,938	$2,625	$831	$1,285	$163	$18	$16
1908	Buildings and Fixtures	gp	$2,733,924	$1,453,360	$459,924	$711,548	$90,102	$10,049	$8,943
1910	Leasehold Improvements	gp	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	gp	$197,922	$105,216	$33,296	$51,512	$6,523	$727	$647
1920	Computer Equipment - Hardware	gp	$244,809	$130,141	$41,184	$63,715	$8,068	$900	$801
1925	Computer Software	gp	$709,106	$376,962	$119,292	$184,556	$23,370	$2,606	$2,319
1930	Transportation Equipment	gp	$1,119,965	$595,376	$188,410	$291,489	$36,911	$4,116	$3,663
1935	Stores Equipment	gp	$34,825	$18,513	$5,859	$9,064	$1,148	$128	$114
1940	Tools, Shop and Garage Equipment	gp	$153,358	$81,525	$25,799	$39,914	$5,054	$564	$502
1945	Measurement and Testing Equipment	gp	$16,819	$8,941	$2,829	$4,377	$554	$62	$55
1950	Power Operated Equipment	gp	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	gp	$19,323	$10,272	$3,251	$5,029	$637	$71	$63
1960	Miscellaneous Equipment	gp	$35,302	$18,767	$5,939	$9,188	$1,163	$130	$115
1970	Load Management Controls - Customer Premises	gp	$11,000	$5,848	$1,851	$2,863	$363	$40	$36
1975	Load Management Controls - Utility Premises	gp	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	gp	$7,500	$3,987	$1,262	$1,952	$247	$28	$25
1990	Other Tangible Property	gp	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	co	($3,688,894)	($1,970,962)	($619,690)	($957,727)	($116,063)	($12,952)	($11,500)
2005	Property Under Capital Leases	gp	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	gp	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	accum dep	($17,513,573)	($9,687,833)	($2,878,055)	($4,276,349)	($554,453)	($61,829)	($55,054)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	accum dep	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	NI	($570,284)	($302,679)	($95,981)	($148,541)	($19,064)	($2,126)	($1,893)
4080	Distribution Services Revenue	CREV	($5,005,962)	($3,377,899)	($830,871)	($772,588)	($6,239)	($1,575)	($16,790)
4082	Retail Services Revenues	mi	($19,546)	($14,853)	($3,195)	($1,377)	($6)	($68)	($47)
4084	Service Transaction Requests (STR) Revenues	mi	($443)	($336)	($72)	($31)	($0)	($2)	($1)
4090	Electric Services Incidental to Energy Sales	mi	($26,087)	($19,823)	($4,265)	($1,837)	($8)	($91)	($63)
4205	Interdepartmental Rents	mi	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	mi	($54,516)	($28,934)	($9,175)	($14,200)	($1,822)	($203)	($181)
4215	Other Utility Operating Income	mi	($15,272)	($8,105)	($2,570)	($3,978)	($511)	($57)	($51)
4220	Other Electric Revenues	mi	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	mi	($37,522)	($27,849)	($6,079)	($3,535)	($8)	($8)	($45)
4235	Miscellaneous Service Revenues	mi	($159,163)	($120,945)	($26,020)	($11,210)	($48)	($554)	($385)
4240	Provision for Rate Refunds	mi	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	mi	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	mi	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	mi	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	mi	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	mi	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	mi	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	mi	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	mi	($800)	($425)	($135)	($208)	($27)	($3)	($3)
4360	Loss on Disposition of Utility and Other Property	mi	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0

4370	Losses from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	mi	($500)	($265)	($84)	($130)	($17)	($2)	($2)
4395	Rate-Payer Benefit Including Interest	mi	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	mi	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	mi	($42,423)	($22,516)	($7,140)	($11,050)	($1,418)	($158)	($141)
4415	Equity in Earnings of Subsidiary Companies	mi	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	cop	$15,828,613	$5,398,148	$2,476,025	$7,807,895	$114,330	$8,257	$23,958
4708	Charges-WMS	cop	$1,694,433	$577,865	$265,055	$835,825	$12,239	$884	$2,565
4710	Cost of Power Adjustments	cop	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	cop	$205,513	$70,088	$32,148	$101,375	$1,484	$107	$311
4714	Charges-NW	cop	$1,235,637	$421,398	$193,287	$609,512	$8,925	$645	$1,870
4715	System Control and Load Dispatching	cop	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	cop	$702,316	$239,516	$109,861	$346,437	$5,073	$366	$1,063
4730	Rural Rate Assistance Expense	cop	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	di	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	di	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	di	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	di	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	di	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	di	$1,013	$342	$215	$456	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	di	$66,355	$22,425	$14,098	$29,832	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	di	$3,758	$2,220	$578	$769	$157	$17	$16
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	di	$1,080	$638	$166	$221	$45	$5	$4
5030	Overhead Subtransmission Feeders - Operation	di	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	di	$3,558	$1,717	$653	$1,037	$124	$14	$12
5040	Underground Distribution Lines and Feeders - Operation Labour	di	$1,492	$728	$249	$441	$61	$7	$6
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	di	$270	$132	$45	$80	$11	$1	$1
5050	Underground Subtransmission Feeders - Operation	di	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	di	$694	$335	$127	$202	$24	$3	$2
5065	Meter Expense	cu	$103,931	$52,633	$23,720	$27,579	$0	$0	$0
5070	Customer Premises - Operation Labour	cu	$44,701	$34,267	$3,686	$454	$5,199	$580	$515
5075	Customer Premises - Materials and Expenses	cu	$19,505	$14,952	$1,608	$198	$2,269	$253	$225
5085	Miscellaneous Distribution Expense	di	$156,263	$83,314	$26,019	$41,003	$4,896	$546	$486
5090	Underground Distribution Lines and Feeders - Rental Paid	di	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	di	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	di	$6,325	$4,102	$1,012	$1,058	$118	$20	$16
5105	Maintenance Supervision and Engineering	di	$128,570	$68,549	$21,408	$33,737	$4,028	$449	$400
5110	Maintenance of Buildings and Fixtures - Distribution Stations	di	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	di	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	di	$11,345	$3,834	$2,411	$5,101	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	di	$23,374	$14,781	$3,474	$3,930	$982	$110	$97
5125	Maintenance of Overhead Conductors and Devices	di	$69,136	$37,651	$11,047	$16,988	$2,850	$318	$282
5130	Maintenance of Overhead Services	di	$19,169	$17,545	$1,467	$157	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	di	$104,245	$61,597	$16,044	$21,348	$4,342	$485	$430
5145	Maintenance of Underground Conduit	di	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	di	$10,732	$5,237	$1,792	$3,174	$437	$49	$43
5155	Maintenance of Underground Services	di	$80,437	$73,620	$6,157	$660	$0	$0	$0

5160	Maintenance of Line Transformers	di	$45,413	$21,923	$8,333	$13,236	$1,587	$177	$157
5175	Maintenance of Meters	cu	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	cu	$26,093	$19,827	$4,266	$1,838	$8	$91	$63
5310	Meter Reading Expense	cu	$114,976	$82,192	$20,003	$12,780	$0	$0	$0
5315	Customer Billing	cu	$238,412	$181,165	$38,976	$16,792	$72	$830	$577
5320	Collecting	cu	$160,472	$121,940	$26,234	$11,302	$49	$558	$388
5325	Collecting- Cash Over and Short	cu	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	cu	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	cu	$20,000	$20,000	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	cu	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	ad	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	ad	$28,862	$18,717	$4,617	$4,826	$538	$89	$74
5415	Energy Conservation	ad	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	ad	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	ad	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	ad	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	ad	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	ad	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	ad	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	ad	$386,005	$250,324	$61,755	$64,550	$7,200	$1,192	$983
5610	Management Salaries and Expenses	ad	$132,149	$85,699	$21,142	$22,099	$2,465	$408	$337
5615	General Administrative Salaries and Expenses	ad	$270,196	$175,222	$43,227	$45,184	$5,040	$834	$688
5620	Office Supplies and Expenses	ad	$53,799	$34,888	$8,607	$8,997	$1,004	$166	$137
5625	Administrative Expense Transferred Credit	ad	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	ad	$123,329	$79,979	$19,731	$20,624	$2,301	$381	$314
5635	Property Insurance	ad	$26,412	$14,041	$4,443	$6,874	$870	$97	$86
5640	Injuries and Damages	ad	$20,253	$13,134	$3,240	$3,387	$378	$63	$52
5645	Employee Pensions and Benefits	ad	$37,330	$24,209	$5,972	$6,243	$696	$115	$95
5650	Franchise Requirements	ad	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	ad	$77,072	$49,981	$12,330	$12,888	$1,438	$238	$196
5660	General Advertising Expenses	ad	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	ad	$74,656	$48,414	$11,944	$12,484	$1,393	$231	$190
5670	Rent	ad	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	ad	$77,632	$50,344	$12,420	$12,982	$1,448	$240	$198
5680	Electrical Safety Authority Fees	ad	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	cop	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	dep	$1,119,762	$611,716	$185,171	$278,857	$36,354	$4,055	$3,608
5710	Amortization of Limited Term Electric Plant	dep	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	dep	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	dep	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	dep	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	dep	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	dep	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	INT	$652,936	$346,546	$109,892	$170,069	$21,827	$2,434	$2,167
6105	Taxes Other Than Income Taxes	ad	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	Input	$250,237	$132,814	$42,116	$65,179	$8,365	$933	$831
6205	Donations	ad	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	ad	$0	$0	$0	$0	$0	$0	$0

6215	Penalties	ad	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	ad	$0	$0	$0	$0	$0	$0	$0
			$32,959,703	$13,329,158	$5,300,241	$13,470,960	$712,662	$75,059	$71,623
				$32,959,703					

Grouping by Allocator	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 78,713	$ 26,602	$ 16,724	$ 35,388	$ -	$ -	$ -
1830	$ 23,374	$ 14,781	$ 3,474	$ 3,930	$ 982	$ 110	$ 97
1835	$ 69,136	$ 37,651	$ 11,047	$ 16,988	$ 2,850	$ 318	$ 282
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 10,732	$ 5,237	$ 1,792	$ 3,174	$ 437	$ 49	$ 43
1850	$ 49,665	$ 23,976	$ 9,113	$ 14,475	$ 1,735	$ 194	$ 172
1855	$ 99,606	$ 91,165	$ 7,624	$ 817	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 284,833	$ 151,862	$ 47,426	$ 74,740	$ 8,924	$ 995	$ 886
1830 & 1835	$ 109,083	$ 64,456	$ 16,788	$ 22,338	$ 4,543	$ 507	$ 450
1840 & 1845	$ 1,762	$ 860	$ 294	$ 521	$ 72	$ 8	$ 7
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -
Break Out	-$ 20,082,705	-$ 11,047,079	-$ 3,312,573	-$ 4,955,219	-$ 634,162	-$ 70,726	-$ 62,946
CCA	$ 64,207	$ 49,219	$ 5,295	$ 652	$ 7,468	$ 833	$ 740
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 2,126,436	$ 725,194	$ 332,632	$ 1,048,923	$ 15,359	$ 1,109	$ 3,219
CEN EWMP	$ 17,728,559	$ 6,046,101	$ 2,773,228	$ 8,745,096	$ 128,053	$ 9,248	$ 26,834
CREV	-$ 5,005,962	-$ 3,377,899	-$ 830,871	-$ 772,588	-$ 6,239	-$ 1,575	-$ 16,790
CWCS	$ 2,394,181	$ 2,191,293	$ 183,253	$ 19,634	$ -	$ -	$ -
CWMC	$ 1,968,963	$ 997,129	$ 449,364	$ 522,471	$ -	$ -	$ -
CWMR	$ 114,976	$ 82,192	$ 20,003	$ 12,780	$ -	$ -	$ -
CWNB	$ 219,738	$ 166,975	$ 35,923	$ 15,476	$ 66	$ 765	$ 532
DCP	$ 78,239	$ 28,938	$ 13,903	$ 34,772	$ 502	$ 36	$ 88
LPHA	-$ 37,522	-$ 27,849	-$ 6,079	-$ 3,535	-$ 8	-$ 8	-$ 45
LTNCP	$ 8,711,874	$ 4,205,641	$ 1,598,566	$ 2,539,140	$ 304,398	$ 33,969	$ 30,160
NFA	$ 219,378	$ 116,435	$ 36,922	$ 57,141	$ 7,334	$ 818	$ 728
NFA ECC	$ 5,459,602	$ 2,902,336	$ 918,460	$ 1,420,949	$ 179,931	$ 20,067	$ 17,858
O&M	$ 1,287,607	$ 835,014	$ 205,997	$ 215,322	$ 24,018	$ 3,976	$ 3,280
PNCP	$ 14,005,227	$ 6,716,601	$ 2,374,071	$ 4,262,936	$ 538,227	$ 60,063	$ 53,328
SNCP	$ 2,960,000	$ 2,282,329	$ 387,862	$ 134,637	$ 128,169	$ 14,303	$ 12,699
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 32,959,703**	**$ 13,329,158**	**$ 5,300,241**	**$ 13,470,960**	**$ 712,662**	**$ 75,059**	**$ 71,623**

2006 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247
Friday, August 28, 2009

Sheet O5 Details of Allocators by Class and Account Worksheet - Second Run

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Categorization Demand	Customer	Total
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0		$0	$0	$0	$0
1805	Land	$29,126	($29,126)	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$29,126	$29,126	$29,126	$0	$29,126
1806	Land Rights	$33,817	($33,817)	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$33,817	$33,817	$33,817	$0	$33,817
1808	Buildings and Fixtures	$15,296	($15,296)	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$15,296	$15,296	$15,296	$0	$15,296
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$972,062	($972,062)	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$783,580	$783,580	$783,580	$0	$783,580
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$188,483	$188,483	$0	$188,483	$188,483
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$4,295,516	($4,295,516)	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$2,104,803	$2,104,803	$1,368,122	$736,681	$2,104,803
1830-5	Poles, Towers and Fixtures - Secondary	$0	$2,190,713	$2,190,713	$1,423,964	$766,750	$2,190,713
1835	Overhead Conductors and Devices	$3,846,432	($3,846,432)	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$3,077,146	$3,077,146	$2,000,145	$1,077,001	$3,077,146
1835-5	Overhead Conductors and Devices - Secondary	$0	$769,286	$769,286	$500,036	$269,250	$769,286
1840	Underground Conduit	$3,819,364	($3,819,364)	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$3,819,364	$3,819,364	$2,482,587	$1,336,778	$3,819,364

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out - Includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$4,220,334	($4,220,334)	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$4,220,334	$4,220,334	$2,743,217	$1,477,117	$4,220,334
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$8,711,874	$0	$8,711,874	$6,098,311	$2,613,562	$8,711,874
1855	Services	$2,394,181	$0	$2,394,181	$0	$2,394,181	$2,394,181
1860	Meters	$1,865,032	$0	$1,865,032	$0	$1,865,032	$1,865,032
1905	Land	$144,400	$0	$144,400	$0	$0	$0
1906	Land Rights	$4,938	$0	$4,938	$0	$0	$0
1908	Buildings and Fixtures	$2,733,924	$0	$2,733,924	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$197,922	$0	$197,922	$0	$0	$0
1920	Computer Equipment - Hardware	$244,809	$0	$244,809	$0	$0	$0
1925	Computer Software	$709,106	$0	$709,106	$0	$0	$0
1930	Transportation Equipment	$1,119,965	$0	$1,119,965	$0	$0	$0
1935	Stores Equipment	$34,825	$0	$34,825	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$153,358	$0	$153,358	$0	$0	$0
1945	Measurement and Testing Equipment	$16,819	$0	$16,819	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$19,323	$0	$19,323	$0	$0	$0
1960	Miscellaneous Equipment	$35,302	$0	$35,302	$0	$0	$0
1970	Load Management Controls - Customer Premises	$11,000	$0	$11,000	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$7,500	$0	$7,500	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	($3,688,894)		($3,688,894)			$0
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($17,513,537)		($17,513,537)			$0
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0		$0			$0
3046	Balance Transferred From Income	($570,284)		($570,284)	$0	$0	$0
4080	Distribution Services Revenue	($5,005,962)		($5,005,962)	$0	$0	$0
4082	Retail Services Revenues	($19,546)		($19,546)	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	($443)		($443)	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	($26,087)		($26,087)	$0	$0	$0
4205	Interdepartmental Rents	$0		$0	$0	$0	$0
4210	Rent from Electric Property	($54,516)		($54,516)	$0	$0	$0
4215	Other Utility Operating Income	($15,272)		($15,272)	$0	$0	$0
4220	Other Electric Revenues	$0		$0	$0	$0	$0
4225	Late Payment Charges	($37,522)		($37,522)	$0	$0	$0
4235	Miscellaneous Service Revenues	($159,163)		($159,163)	$0	$0	$0
4240	Provision for Rate Refunds	$0		$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0		$0	$0	$0	$0
4305	Regulatory Debits	$0		$0	$0	$0	$0
4310	Regulatory Credits	$0		$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	$0		$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0		$0	$0	$0	$0

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out - Includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total
4325	Revenues from Merchandise, Jobbing, Etc.	$0		$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0		$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0		$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0		$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0		$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0		$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	($800)		($800)	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$0		$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0		$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0		$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	($500)		($500)	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0		$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0		$0	$0	$0	$0
4405	Interest and Dividend Income	($42,423)		($42,423)	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	$0		$0	$0	$0	$0
4705	Power Purchased	$15,828,613		$15,828,613	$0	$0	$0
4708	Charges-WMS	$1,694,433		$1,694,433	$0	$0	$0
4710	Cost of Power Adjustments	$0		$0	$0	$0	$0
4712	Charges-One-Time	$205,513		$205,513	$0	$0	$0
4714	Charges-NW	$1,235,637		$1,235,637	$0	$0	$0
4715	System Control and Load Dispatching	$0		$0	$0	$0	$0
4716	Charges-CN	$702,316		$702,316	$0	$0	$0
4730	Rural Rate Assistance Expense	$0		$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0		$0	$0	$0	$0
5010	Load Dispatching	$0		$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0		$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0		$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0		$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$1,013		$1,013	$1,013	$0	$1,013
5017	Distribution Station Equipment - Operation Supplies and Expenses	$66,355		$66,355	$66,355	$0	$66,355
5020	Overhead Distribution Lines and Feeders - Operation Labour	$3,758		$3,758	$2,442	$1,315	$3,758
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$1,080		$1,080	$702	$378	$1,080
5030	Overhead Subtransmission Feeders - Operation	$0		$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$3,558		$3,558	$2,490	$1,067	$3,558
5040	Underground Distribution Lines and Feeders - Operation Labour	$1,492		$1,492	$970	$522	$1,492
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$270		$270	$176	$95	$270
5050	Underground Subtransmission Feeders - Operation	$0		$0	$0	$0	$0

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out - Includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total
5055	Underground Distribution Transformers - Operation	$694		$694	$486	$208	$694
5065	Meter Expense	$103,931		$103,931	$0	$103,931	$103,931
5070	Customer Premises - Operation Labour	$44,701		$44,701	$0	$44,701	$44,701
5075	Customer Premises - Materials and Expenses	$19,505		$19,505	$0	$19,505	$19,505
5085	Miscellaneous Distribution Expense	$156,263		$156,263	$101,571	$54,692	$156,263
5090	Underground Distribution Lines and Feeders - Rental Paid	$0		$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0		$0	$0	$0	$0
5096	Other Rent	$6,325		$6,325	$0	$0	$0
5105	Maintenance Supervision and Engineering	$128,570		$128,570	$83,571	$45,000	$128,570
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0		$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0		$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$11,345		$11,345	$11,345	$0	$11,345
5120	Maintenance of Poles, Towers and Fixtures	$23,374		$23,374	$15,193	$8,181	$23,374
5125	Maintenance of Overhead Conductors and Devices	$69,136		$69,136	$44,938	$24,198	$69,136
5130	Maintenance of Overhead Services	$19,169		$19,169	$0	$19,169	$19,169
5135	Overhead Distribution Lines and Feeders - Right of Way	$104,245		$104,245	$67,760	$36,486	$104,245
5145	Maintenance of Underground Conduit	$0		$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$10,732		$10,732	$6,976	$3,756	$10,732
5155	Maintenance of Underground Services	$80,437		$80,437	$0	$80,437	$80,437
5160	Maintenance of Line Transformers	$45,413		$45,413	$31,789	$13,624	$45,413
5175	Maintenance of Meters	$0		$0	$0	$0	$0
5305	Supervision	$26,093		$26,093	$0	$26,093	$26,093
5310	Meter Reading Expense	$114,976		$114,976	$0	$114,976	$114,976
5315	Customer Billing	$238,412		$238,412	$0	$238,412	$238,412
5320	Collecting	$160,472		$160,472	$0	$160,472	$160,472
5325	Collecting- Cash Over and Short	$0		$0	$0	$0	$0
5330	Collection Charges	$0		$0	$0	$0	$0
5335	Bad Debt Expense	$20,000		$20,000	$0	$20,000	$20,000
5340	Miscellaneous Customer Accounts Expenses	$0		$0	$0	$0	$0
5405	Supervision	$0		$0			$0
5410	Community Relations - Sundry	$28,862		$28,862			$0
5415	Energy Conservation	$0		$0			$0
5420	Community Safety Program	$0		$0			$0
5425	Miscellaneous Customer Service and Informational Expenses	$0		$0			$0
5505	Supervision	$0		$0			$0
5510	Demonstrating and Selling Expense	$0		$0			$0
5515	Advertising Expense	$0		$0			$0
5520	Miscellaneous Sales Expense	$0		$0			$0
5605	Executive Salaries and Expenses	$386,005		$386,005			$0
5610	Management Salaries and Expenses	$132,149		$132,149			$0
5615	General Administrative Salaries and Expenses	$270,196		$270,196			$0
5620	Office Supplies and Expenses	$53,799		$53,799			$0
5625	Administrative Expense Transferred Credit	$0		$0			$0
5630	Outside Services Employed	$123,329		$123,329			$0
5635	Property Insurance	$26,412		$26,412			$0

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out - Includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total
5640	Injuries and Damages	$20,253		$20,253			$0
5645	Employee Pensions and Benefits	$37,330		$37,330			$0
5650	Franchise Requirements	$0		$0			$0
5655	Regulatory Expenses	$77,072		$77,072			$0
5660	General Advertising Expenses	$0		$0			$0
5665	Miscellaneous General Expenses	$74,656		$74,656			$0
5670	Rent	$0		$0			$0
5675	Maintenance of General Plant	$77,632		$77,632			$0
5680	Electrical Safety Authority Fees	$0		$0			$0
5685	Independent Market Operator Fees and Penalties	$0		$0			$0
5705	Amortization Expense - Property, Plant, and Equipment	$1,119,762	$0	$1,119,762			$0
5710	Amortization of Limited Term Electric Plant	$0	$0	$0			$0
5715	Amortization of Intangibles and Other Electric Plant	$0	$0	$0			$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0			$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0		$0			
5735	Amortization of Deferred Development Costs	$0		$0			
5740	Amortization of Deferred Charges	$0		$0			
6005	Interest on Long Term Debt	$652,936		$652,936			
6105	Taxes Other Than Income Taxes	$0		$0	$0	$0	$0
6110	Income Taxes	$250,237		$250,237			$0
6205	Donations	$0		$0	$0	$0	$0
6210	Life Insurance	$0		$0	$0	$0	$0
6215	Penalties	$0		$0	$0	$0	$0
6225	Other Deductions	$0		$0	$0	$0	$0
		$32,959,738	$0	$32,959,738	$17,915,978	$13,742,053	$31,658,031
							O5 Summary
					$9,922,225	$7,665,762	$32,959,703
							$36
				$0			**$32,959,738**

Grouping by Allocator

	Adjusted TB	Demand	Customer	Total	Residential	GS <50
1808	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 78,713.48	$ 78,713.48	$ -	$ 78,713.48	$ 26,601.51	$ 16,724.29
1830	$ 23,374.17	$ 15,193.21	$ 8,180.96	$ 23,374.17	$ 8,305.53	$ 3,001.56
1835	$ 69,136.07	$ 44,938.45	$ 24,197.62	$ 69,136.07	$ 18,865.14	$ 9,285.31
1840	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 10,732.46	$ 6,976.10	$ 3,756.36	$ 10,732.46	$ 2,357.60	$ 1,482.22
1850	$ 49,664.86	$ 34,765.40	$ 14,899.46	$ 49,664.86	$ 12,538.34	$ 7,882.82
1855	$ 99,605.89	$ -	$ 99,605.89	$ 99,605.89	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 284,833.36	$ 185,141.69	$ 99,691.68	$ 284,833.36	$ 72,420.16	$ 39,664.72
1830 & 1835	$ 109,083.02	$ 70,903.96	$ 38,179.06	$ 109,083.02	$ 34,510.99	$ 14,311.34
1840 & 1845	$ 1,762.34	$ 1,145.52	$ 616.82	$ 1,762.34	$ 387.13	$ 243.39
BCP	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 20,000.00	$ -	$ 20,000.00	$ 20,000.00	$ -	$ -
Break Out	$ (20,082,669.23)	$ -	$ -	$ -	$ (3,904,816.65)	$ (2,124,514.34)
CCA	$ 64,206.61	$ -	$ 64,206.61	$ 64,206.61	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 2,126,436.25	$ -	$ 188,482.91	$ 188,482.91	$ -	$ -

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total
	CEN EWMP	$ 17,728,559.26	$ -	$ -	$ -	$ -	$ -
	CREV	$ (5,005,962.30)	$ -	$ -	$ -	$ -	$ -
	CWCS	$ 2,394,180.51	$ -	$ 2,394,180.51	$ 2,394,180.51	$ -	$ -
	CWMC	$ 1,968,963.16	$ -	$ 1,968,963.16	$ 1,968,963.16	$ -	$ -
	CWMR	$ 114,976.26	$ -	$ 114,976.26	$ 114,976.26	$ -	$ -
	CWNB	$ 219,737.93	$ -	$ 424,977.22	$ 424,977.22	$ -	$ -
	DCP	$ 78,239.28	$ 78,239.28	$ -	$ 78,239.28	$ 28,937.91	$ 13,903.12
	LPHA	$ (37,522.00)	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 8,711,873.54	$ 6,098,311.48	$ 2,613,562.06	$ 8,711,873.54	$ 2,199,390.82	$ 1,382,750.59
	NFA	$ 219,378.44	$ -	$ -	$ -	$ -	$ -
	NFA ECC	$ 5,459,602.22	$ -	$ -	$ -	$ -	$ -
	O&M	$ 1,287,606.59	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 14,005,226.55	$ 9,377,650.10	$ 4,627,576.45	$ 14,005,226.55	$ 3,169,211.18	$ 1,992,473.82
	SNCP	$ 2,959,999.72	$ 1,923,999.82	$ 1,035,999.90	$ 2,959,999.72	$ 1,437,579.59	$ 352,539.86
	TCP	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 32,959,738**	**$ 17,915,978**	**$ 13,742,053**	**$ 31,658,031**	**$ 3,106,289**	**$ 1,709,749**

Ontario

2006 COST ALLOCA

Orangeville Hydr

EB-2002-0400 EB-20

Friday, August 28, 2

Sheet O5 Details

Uniform System of Accou

		Allocation - Demand Related						
		1	2	3	7	8	9	
USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Demand
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$10,773	$5,176	$12,944	$187	$13	$33	$29,126
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$12,508	$6,009	$15,029	$217	$16	$38	$33,817
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$5,658	$2,718	$6,798	$98	$7	$17	$15,296
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$264,814	$166,488	$352,278	$0	$0	$0	$783,580
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$462,362	$290,686	$615,075	$0	$0	$0	$1,368,122
1830-5	Poles, Towers and Fixtures - Secondary	$1,063,961	$260,917	$99,086	$0	$0	$0	$1,423,964
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$675,956	$424,972	$899,217	$0	$0	$0	$2,000,145
1835-5	Overhead Conductors and Devices - Secondary	$373,618	$91,623	$34,795	$0	$0	$0	$500,036
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$838,999	$527,476	$1,116,111	$0	$0	$0	$2,482,587

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Demand
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$927,080	$582,853	$1,233,284	$0	$0	$0	$2,743,217
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$2,199,391	$1,382,751	$2,516,170	$0	$0	$0	$6,098,311
1855	Services	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0
1905	Land	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	($744,493)	($464,686)	($895,904)	$0	$0	$0	($2,105,083)
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($3,373,780)	($1,775,212)	($3,208,122)	($166)	($12)	($29)	($8,357,322)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	$0	$0	$0	$0	$0	$0	$0
4080	Distribution Services Revenue	$0	$0	$0	$0	$0	$0	$0
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$0	$0	$0	$0	$0	$0	$0
4215	Other Utility Operating Income	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	$0	$0	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0
4240	Provision for Rate Refunds	$0	$0	$0				$0
4245	Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0	$0	$0				$0
4310	Regulatory Credits	$0	$0	$0				$0
4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Demand
4325	Revenues from Merchandise, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	$0	$0	$0	$0	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$0	$0	$0	$0	$0	$0	$0
4708	Charges-WMS	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$342	$215	$456	$0	$0	$0	$1,013
5017	Distribution Station Equipment - Operation Supplies and Expenses	$22,425	$14,098	$29,832	$0	$0	$0	$66,355
5020	Overhead Distribution Lines and Feeders - Operation Labour	$1,189	$493	$761	$0	$0	$0	$2,442
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$342	$142	$219	$0	$0	$0	$702
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$898	$565	$1,027	$0	$0	$0	$2,490
5040	Underground Distribution Lines and Feeders - Operation Labour	$328	$206	$436	$0	$0	$0	$970
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$59	$37	$79	$0	$0	$0	$176
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Demand
5055	Underground Distribution Transformers - Operation	$175	$110	$200	$0	$0	$0	$486
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$39,731	$21,761	$40,080	$0	$0	$0	$101,571
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$32,690	$17,904	$32,977	$0	$0	$0	$83,571
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$3,834	$2,411	$5,101	$0	$0	$0	$11,345
5120	Maintenance of Poles, Towers and Fixtures	$8,306	$3,002	$3,886	$0	$0	$0	$15,193
5125	Maintenance of Overhead Conductors and Devices	$18,865	$9,285	$16,788	$0	$0	$0	$44,938
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$32,981	$13,677	$21,102	$0	$0	$0	$67,760
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$2,358	$1,482	$3,136	$0	$0	$0	$6,976
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$11,465	$7,208	$13,116	$0	$0	$0	$31,789
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0
5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0
5320	Collecting	$0	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$0	$0	$0	$0	$0	$0	$0
5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0
5610	Management Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0
5620	Office Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$0	$0	$0	$0	$0	$0	$0
5635	Property Insurance	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Demand
5640	Injuries and Damages	$0	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefits	$0	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$0	$0	$0	$0	$0	$0	$0
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$0	$0	$0	$0	$0	$0	$0
5670	Rent	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$0	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$213,457	$115,383	$211,330	$9	$1	$2	$540,180
5710	Amortization of Limited Term Electric Plant	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs							
5735	Amortization of Deferred Development Costs							
5740	Amortization of Deferred Charges							
6005	Interest on Long Term Debt	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$0	$0	$0	$0	$0	$0	$0
6205	Donations	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0
		$3,106,289	$1,709,749	$3,177,286	$344	$25	$60	$7,993,754
		O4 Summary						
		$32,959,703						

Grouping by Allocator	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	GS <50
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 35,387.68	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ 3,886.12	$ -	$ -	$ -	$ -	$ -	$ 472.81
1835	$ 16,788.00	$ -	$ -	$ -	$ -	$ -	$ 1,761.30
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 3,136.29	$ -	$ -	$ -	$ -	$ -	$ 309.76
1850	$ 14,344.24	$ -	$ -	$ -	$ -	$ -	$ 1,230.32
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,623.94
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 73,056.81	$ -	$ -	$ -	$ -	$ -	$ 7,761.33
1830 & 1835	$ 22,081.64	$ -	$ -	$ -	$ -	$ -	$ 2,476.98
1840 & 1845	$ 515.00	$ -	$ -	$ -	$ -	$ -	$ 50.86
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ (3,892,697.18)	$ -	$ -	$ (27.68)	$ -	$ -	$ (768,376.51)
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,294.58
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,483.85

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Demand
	CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ 183,253.14
	CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ 449,363.52
	CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,003.34
	CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ 69,476.55
	DCP	$ 34,771.80	$ -	$ -	$ 88.10	$ -	$ -	$ -
	LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 2,516,170.07	$ -	$ -	$ -	$ -	$ -	$ 215,814.97
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 4,215,965.10	$ -	$ -	$ -	$ -	$ -	$ 381,597.34
	SNCP	$ 133,880.37	$ -	$ -	$ -	$ -	$ -	$ 35,322.28
	TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 3,177,286**	**$ -**	**$ -**	**$ 60**	**$ -**	**$ -**	**$ 642,920**

2006 COST ALLOCA

Orangeville Hydr

EB-2002-0400 EB-20

Friday, August 28, 2

Sheet O5 Details

Allocation - Customer Related

		1	2	3	7	8	9	
USoA Account #	Uniform System of Accour Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Customer
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$64,280	$29,484	$92,974	$1,361	$98	$285	$188,483
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$564,722	$60,748	$7,478	$85,682	$9,562	$8,490	$736,681
1830-5	Poles, Towers and Fixtures - Secondary	$625,204	$26,142	$560	$94,859	$10,586	$9,399	$766,750
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$825,603	$88,811	$10,932	$125,265	$13,979	$12,411	$1,077,001
1835-5	Overhead Conductors and Devices - Secondary	$219,545	$9,180	$197	$33,310	$3,717	$3,300	$269,250
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$1,024,742	$110,233	$13,569	$155,479	$17,351	$15,405	$1,336,778

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Customer
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$1,132,322	$121,805	$14,993	$171,801	$19,172	$17,022	$1,477,117
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$2,006,250	$215,815	$22,970	$304,398	$33,969	$30,160	$2,613,562
1855	Services	$2,191,293	$183,253	$19,634	$0	$0	$0	$2,394,181
1860	Meters	$944,496	$425,644	$494,892	$0	$0	$0	$1,865,032
1905	Land	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	($1,226,469)	($155,004)	($61,823)	($116,063)	($12,952)	($11,500)	($1,583,811)
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($4,891,682)	($652,726)	($371,851)	($466,106)	($51,982)	($46,273)	($6,480,620)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	$0	$0	$0	$0	$0	$0	$0
4080	Distribution Services Revenue	$0	$0	$0	$0	$0	$0	$0
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$0	$0	$0	$0	$0	$0	$0
4215	Other Utility Operating Income	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	$0	$0	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0
4240	Provision for Rate Refunds	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accoun

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Customer
4325	Revenues from Merchandise, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	$0	$0	$0	$0	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$0	$0	$0	$0	$0	$0	$0
4708	Charges-WMS	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$1,031	$85	$9	$157	$17	$16	$1,315
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$296	$25	$3	$45	$5	$4	$378
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$819	$88	$9	$124	$14	$12	$1,067
5040	Underground Distribution Lines and Feeders - Operation Labour	$400	$43	$5	$61	$7	$6	$522
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$72	$8	$1	$11	$1	$1	$95
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Customer
5055	Underground Distribution Transformers - Operation	$160	$17	$2	$24	$3	$2	$208
5065	Meter Expense	$52,633	$23,720	$27,579	$0	$0	$0	$103,931
5070	Customer Premises - Operation Labour	$34,267	$3,686	$454	$5,199	$580	$515	$44,701
5075	Customer Premises - Materials and Expenses	$14,952	$1,608	$198	$2,269	$253	$225	$19,505
5085	Miscellaneous Distribution Expense	$43,583	$4,258	$923	$4,896	$546	$486	$54,692
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$35,859	$3,503	$760	$4,028	$449	$400	$45,000
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$6,475	$473	$44	$982	$110	$97	$8,181
5125	Maintenance of Overhead Conductors and Devices	$18,786	$1,761	$200	$2,850	$318	$282	$24,198
5130	Maintenance of Overhead Services	$17,545	$1,467	$157	$0	$0	$0	$19,169
5135	Overhead Distribution Lines and Feeders - Right of Way	$28,617	$2,367	$245	$4,342	$485	$430	$36,486
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$2,880	$310	$38	$437	$49	$43	$3,756
5155	Maintenance of Underground Services	$73,620	$6,157	$660	$0	$0	$0	$80,437
5160	Maintenance of Line Transformers	$10,458	$1,125	$120	$1,587	$177	$157	$13,624
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$19,827	$4,266	$1,838	$8	$91	$63	$26,093
5310	Meter Reading Expense	$82,192	$20,003	$12,780	$0	$0	$0	$114,976
5315	Customer Billing	$181,165	$38,976	$16,792	$72	$830	$577	$238,412
5320	Collecting	$121,940	$26,234	$11,302	$49	$558	$388	$160,472
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$20,000	$0	$0	$0	$0	$0	$20,000
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$0	$0	$0	$0	$0	$0	$0
5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0
5610	Management Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0
5620	Office Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$0	$0	$0	$0	$0	$0	$0
5635	Property Insurance	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Customer
5640	Injuries and Damages	$0	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefits	$0	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$0	$0	$0	$0	$0	$0	$0
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$0	$0	$0	$0	$0	$0	$0
5670	Rent	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$0	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$302,086	$39,354	$20,442	$30,383	$3,389	$3,015	$398,669
5710	Amortization of Limited Term Electric Plant	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs							
5735	Amortization of Deferred Development Costs							
5740	Amortization of Deferred Charges							
6005	Interest on Long Term Debt	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$0	$0	$0	$0	$0	$0	$0
6205	Donations	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0
		$4,549,973	$642,920	$339,085	$447,511	$51,381	$45,421	$6,076,291

Grouping by Allocator	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	GS <50
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ 43.74	$ -	$ -	$ 97.34	$ -	$ -	$ -
1835	$ 200.03	$ -	$ -	$ 282.41	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 38.13	$ -	$ -	$ 43.29	$ -	$ -	$ -
1850	$ 130.95	$ -	$ -	$ 171.94	$ -	$ -	$ -
1855	$ 816.85	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 1,682.73	$ -	$ -	$ 885.61	$ -	$ -	$ -
1830 & 1835	$ 256.78	$ -	$ -	$ 450.16	$ -	$ -	$ -
1840 & 1845	$ 6.26	$ -	$ -	$ 7.11	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ (413,231.42)	$ -	$ -	$ (54,758.19)	$ -	$ -	$ -
CCA	$ 651.72	$ -	$ -	$ 739.92	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 92,974.34	$ -	$ -	$ 285.29	$ -	$ -	$ -

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - Customer
	CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ (830,870.71)
	CWCS	$ 19,634.27	$ -	$ -	$ -	$ -	$ -	$ -
	CWMC	$ 522,470.74	$ -	$ -	$ -	$ -	$ -	$ -
	CWMR	$ 12,780.44	$ -	$ -	$ -	$ -	$ -	$ -
	CWNB	$ 29,931.82	$ -	$ -	$ 1,028.81	$ -	$ -	$ (33,553.13)
	DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,078.56)
	LTNCP	$ 22,969.66	$ -	$ -	$ 30,160.17	$ -	$ -	$ -
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ (115,085.63)
	NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 46,971.26	$ -	$ -	$ 53,328.27	$ -	$ -	$ -
	SNCP	$ 756.91	$ -	$ -	$ 12,699.20	$ -	$ -	$ -
	TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**$ 339,085**	**$ -**	**$ -**	**$ 45,421**	**$ -**	**$ -**	**-$ 985,588**

2006 COST ALLOCA

Orangeville Hydr

EB-2002-0400 EB-20

Friday, August 28, 2

Sheet O5 Details

Allocation of Miscellaneous Revenue

		1	2	3	4	5	6	7	8	9	
USoA Account #	Uniform System of Accoun Accounts	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Total - Mis
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$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	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accoun

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Total - Mis
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit										
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment										
2120	Accumulated Amortization of Electric Utility Plant - Intangibles										
3046	Balance Transferred From Income	($302,679)	($95,981)	($148,541)	$0	$0	$0	($19,064)	($2,126)	($1,893)	($570,284)
4080	Distribution Services Revenue	($3,377,899)	($830,871)	($772,588)	$0	$0	$0	($6,239)	($1,575)	($16,790)	($5,005,962)
4082	Retail Services Revenues	($14,853)	($3,195)	($1,377)	$0	$0	$0	($6)	($68)	($47)	($19,546)
4084	Service Transaction Requests (STR) Revenues	($336)	($72)	($31)	$0	$0	$0	($0)	($2)	($1)	($443)
4090	Electric Services Incidental to Energy Sales	($19,823)	($4,265)	($1,837)	$0	$0	$0	($8)	($91)	($63)	($26,087)
4205	Interdepartmental Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	($28,934)	($9,175)	($14,200)	$0	$0	$0	($1,822)	($203)	($181)	($54,516)
4215	Other Utility Operating Income	($8,105)	($2,570)	($3,978)	$0	$0	$0	($511)	($57)	($51)	($15,272)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($27,849)	($6,079)	($3,535)	$0	$0	$0	($8)	($8)	($45)	($37,522)
4235	Miscellaneous Service Revenues	($120,945)	($26,020)	($11,210)	$0	$0	$0	($48)	($554)	($385)	($159,163)
4240	Provision for Rate Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Total - Mis
4325	Revenues from Merchandise, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	($425)	($135)	($208)	$0	$0	$0	($27)	($3)	($3)	($800)
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	($265)	($84)	($130)	$0	$0	$0	($17)	($2)	($2)	($500)
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	($22,516)	($7,140)	($11,050)	$0	$0	$0	($1,418)	($158)	($141)	($42,423)
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4708	Charges-WMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Total - Mis
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5125	Maintenance of Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5610	Management Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5620	Office Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5635	Property Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Total - Mis
5640	Injuries and Damages	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5670	Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment										
5710	Amortization of Limited Term Electric Plant										
5715	Amortization of Intangibles and Other Electric Plant										
5720	Amortization of Electric Plant Acquisition Adjustments										
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		($3,924,631)	($985,588)	($968,685)	$0	$0	$0	($29,167)	($4,846)	($19,602)	($5,932,518)

Grouping by Allocator	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	GS <50
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (419,682.47)
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 303,148.56

Uniform System of Accour

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Total - Mis
	CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,773,228.38
	CREV	$ (772,587.73)	$ -	$ -	$ -	$ (6,239.02)	$ (1,575.03)	$ (16,790.37)	$ -	$ -	$ -
	CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CWNB	$ (14,455.33)	$ -	$ -	$ -	$ (62.11)	$ (714.23)	$ (496.85)	$ -	$ -	$ -
	DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (3,534.57)	$ -	$ -	$ -	$ (7.50)	$ (7.50)	$ (45.03)	$ -	$ -	$ -
	LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	NFA	$ (178,107.17)	$ -	$ -	$ -	$ (22,858.50)	$ (2,548.85)	$ (2,269.85)	$ -	$ -	$ 152,007.98
	NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 918,460.31
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,997.10
	PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	**-$ 968,685**	**$ -**	**$ -**	**$ -**	**-$ 29,167**	**-$ 4,846**	**-$ 19,602**	**$ -**	**$ -**	**$ 3,933,160**

2006 COST ALLOCA

Orangeville Hydr

EB-2002-0400 EB-20

Friday, August 28, 2

Sheet O5 Details

Allocation of General Plant and Administration

Uniform System of Accoun

		1	2	3	7	8	9		
USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - A&G	
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	($0)
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$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
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accou

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - A&G	
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	($0)
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	$76,764	$24,292	$37,583	$4,759	$531	$472	$144,400	$0
1906	Land Rights	$2,625	$831	$1,285	$163	$18	$16	$4,938	$0
1908	Buildings and Fixtures	$1,453,360	$459,924	$711,548	$90,102	$10,049	$8,943	$2,733,924	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$105,216	$33,296	$51,512	$6,523	$727	$647	$197,922	$0
1920	Computer Equipment - Hardware	$130,141	$41,184	$63,715	$8,068	$900	$801	$244,809	$0
1925	Computer Software	$376,962	$119,292	$184,556	$23,370	$2,606	$2,319	$709,106	$0
1930	Transportation Equipment	$595,376	$188,410	$291,489	$36,911	$4,116	$3,663	$1,119,965	$0
1935	Stores Equipment	$18,513	$5,859	$9,064	$1,148	$128	$114	$34,825	$0
1940	Tools, Shop and Garage Equipment	$81,525	$25,799	$39,914	$5,054	$564	$502	$153,358	$0
1945	Measurement and Testing Equipment	$8,941	$2,829	$4,377	$554	$62	$55	$16,819	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$10,272	$3,251	$5,029	$637	$71	$63	$19,323	$0
1960	Miscellaneous Equipment	$18,767	$5,939	$9,188	$1,163	$130	$115	$35,302	$0
1970	Load Management Controls - Customer Premises	$5,848	$1,851	$2,863	$363	$40	$36	$11,000	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$3,987	$1,262	$1,952	$247	$28	$25	$7,500	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	$0	$0	$0	$0	$0	$0	$0	($0)
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)	($2,675,631)	$36
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	$0	$0	$0	$0	$0	$0	$0	($0)
4080	Distribution Services Revenue	$0	$0	$0	$0	$0	$0	$0	$0
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$0	$0	$0	$0	$0	$0	$0	($0)
4215	Other Utility Operating Income	$0	$0	$0	$0	$0	$0	$0	($0)
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	$0	$0	$0	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4240	Provision for Rate Refunds	$0	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	$0	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0

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USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - A&G	
4325	Revenues from Merchandise, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	($0)
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	$0	$0	$0	$0	$0	$0	$0	($0)
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$5,398,148	$2,476,025	$7,807,895	$114,330	$8,257	$23,958	$15,828,613	$0
4708	Charges-WMS	$577,865	$265,055	$835,825	$12,239	$884	$2,565	$1,694,433	$0
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$70,088	$32,148	$101,375	$1,484	$107	$311	$205,513	$0
4714	Charges-NW	$421,398	$193,287	$609,512	$8,925	$645	$1,870	$1,235,637	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$239,516	$109,861	$346,437	$5,073	$366	$1,063	$702,316	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	($0)
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	($0)
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0

Uniform System of Accoun

USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - A&G	
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	($0)
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	($0)
5085	Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$4,102	$1,012	$1,058	$118	$20	$16	$6,325	$0
5105	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
5125	Maintenance of Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	($0)
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	($0)
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	$0	$0	$0	$0	$0	$0	$0
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	($0)
5160	Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0	($0)
5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0	($0)
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$18,717	$4,617	$4,826	$538	$89	$74	$28,862	$0
5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$250,324	$61,755	$64,550	$7,200	$1,192	$983	$386,005	$0
5610	Management Salaries and Expenses	$85,699	$21,142	$22,099	$2,465	$408	$337	$132,149	$0
5615	General Administrative Salaries and Expenses	$175,222	$43,227	$45,184	$5,040	$834	$688	$270,196	$0
5620	Office Supplies and Expenses	$34,888	$8,607	$8,997	$1,004	$166	$137	$53,799	$0
5625	Administrative Expense Transferred Credit	$0	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$79,979	$19,731	$20,624	$2,301	$381	$314	$123,329	$0
5635	Property Insurance	$14,041	$4,443	$6,874	$870	$97	$86	$26,412	$0

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USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - A&G	
5640	Injuries and Damages	$13,134	$3,240	$3,387	$378	$63	$52	$20,253	$0
5645	Employee Pensions and Benefits	$24,209	$5,972	$6,243	$696	$115	$95	$37,330	$0
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$49,981	$12,330	$12,888	$1,438	$238	$196	$77,072	$0
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$48,414	$11,944	$12,484	$1,393	$231	$190	$74,656	$0
5670	Rent	$0	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$50,344	$12,420	$12,982	$1,448	$240	$198	$77,632	$0
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$96,174	$30,435	$47,086	$5,962	$665	$592	$180,913	$0
5710	Amortization of Limited Term Electric Plant	$0	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$0	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	$0	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	$0	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	$346,546	$109,892	$170,069	$21,827	$2,434	$2,167	$652,936	$0
6105	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$132,814	$42,116	$65,179	$8,365	$933	$831	$250,237	$0
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0
		$9,597,527	$3,933,160	$10,923,273	$293,974	$28,499	$45,743	$24,822,177	$36

Grouping by Allocator	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
1808	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ (649,290.54)	$ -	$ -	$ (8,160.14)	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 955,948.40	$ -	$ -	$ 2,933.27	$ -	$ -

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USoA Account #	Accounts	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total - A&G
	CEN EWMP	$ 8,745,095.97	$ -	$ -	$ 26,833.80	$ -	$ -	
	CREV	$ -	$ -	$ -	$ -	$ -	$ -	
	CWCS	$ -	$ -	$ -	$ -	$ -	$ -	
	CWMC	$ -	$ -	$ -	$ -	$ -	$ -	
	CWMR	$ -	$ -	$ -	$ -	$ -	$ -	
	CWNB	$ -	$ -	$ -	$ -	$ -	$ -	
	DCP	$ -	$ -	$ -	$ -	$ -	$ -	
	LPHA	$ -	$ -	$ -	$ -	$ -	$ -	
	LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	
	NFA	$ 235,248.42	$ -	$ -	$ 2,998.07	$ -	$ -	
	NFA ECC	$ 1,420,949.49	$ -	$ -	$ 17,858.17	$ -	$ -	
	O&M	$ 215,321.65	$ -	$ -	$ 3,280.15	$ -	$ -	
	PNCP	$ -	$ -	$ -	$ -	$ -	$ -	
	SNCP	$ -	$ -	$ -	$ -	$ -	$ -	
	TCP	$ -	$ -	$ -	$ -	$ -	$ -	
	Total	**$ 10,923,273**	**$ -**	**$ -**	**$ 45,743**	**$ -**	**$ -**	

2010 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
Friday, August 28, 2009
Sheet O6 Composite Allocator Detail Worksheet - Second Run

Details:

Output Sheet Details How Various Composite Allocators are Derived

Demand Allocators can be found in columns C to AG
Customer Allocators can be found in columns AJ to BN

		Demand Allocators							Customer Allocators							
			1	2	3	7	8	9		1	2	3	7	8	9	
		Demand Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total
Composite Allocators																
Rate Base																
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$10,773	$5,176	$12,944	$187	$13	$33	$0	$0	$0	$0	$0	$0	$0	$0
1805	Total	$29,126	$10,773	$5,176	$12,944	$187	$13	$33	$0	$0	$0	$0	$0	$0	$0	$29,126
1806-1	Land Rights Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$12,508	$6,009	$15,029	$217	$16	$38	$0	$0	$0	$0	$0	$0	$0	$0
1806	Total	$33,817	$12,508	$6,009	$15,029	$217	$16	$38	$0	$0	$0	$0	$0	$0	$0	$33,817
1808-1	Buildings and Fixtures > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$5,658	$2,718	$6,798	$98	$7	$17	$0	$0	$0	$0	$0	$0	$0	$0
1808	Total	$15,296	$5,658	$2,718	$6,798	$98	$7	$17	$0	$0	$0	$0	$0	$0	$0	$15,296
1810-1	Leasehold Improvements >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$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	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$783,580	$264,814	$166,488	$352,278	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$783,580
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$188,483	$64,280	$29,484	$92,974	$1,361	$98	$285	$188,483
1820	Total	$783,580	$264,814	$166,488	$352,278	$0	$0	$0	$188,483	$64,280	$29,484	$92,974	$1,361	$98	$285	$972,062
1815 & 1820	Total	$783,580	$264,814	$166,488	$352,278	$0	$0	$0	$188,483	$64,280	$29,484	$92,974	$1,361	$98	$285	$972,062
1825-1	Storage Battery Equipment > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		$462,362	$290,686	$615,075	$0	$0	$0	$736,681	$564,722	$60,748	$7,478	$85,682	$9,562	$8,490	$736,681
1830-5	Poles, Towers and Fixtures - Secondary		$1,063,961	$260,917	$99,086	$0	$0	$0	$766,750	$625,204	$26,142	$560	$94,859	$10,586	$9,399	$766,750
1830	Total	$2,792,085	$1,526,323	$551,602	$714,160	$0	$0	$0	$1,503,431	$1,189,926	$86,890	$8,038	$180,541	$20,147	$17,888	$4,295,516
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		$675,956	$424,972	$899,217	$0	$0	$0	$1,077,001	$825,603	$88,811	$10,932	$125,265	$13,979	$12,411	$1,077,001
1835-5	Overhead Conductors and Devices - Secondary		$373,618	$91,623	$34,795	$0	$0	$0	$269,250	$219,545	$9,180	$197	$33,310	$3,717	$3,300	$269,250
1835	Total	$2,500,181	$1,049,575	$516,595	$934,012	$0	$0	$0	$1,346,251	$1,045,149	$97,991	$11,129	$158,575	$17,696	$15,712	$3,846,432
1830 & 1835	Total	$5,292,267	$2,575,898	$1,068,197	$1,648,172	$0	$0	$0	$2,849,682	$2,235,075	$184,881	$19,166	$339,116	$37,843	$33,600	$8,141,949
1840-3	Underground Conduit - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		$838,999	$527,476	$1,116,111	$0	$0	$0	$1,336,778	$1,024,742	$110,233	$13,569	$155,479	$17,351	$15,405	$1,336,778
1840-5	Underground Conduit - Secondary		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Total	$2,482,587	$838,999	$527,476	$1,116,111	$0	$0	$0	$1,336,778	$1,024,742	$110,233	$13,569	$155,479	$17,351	$15,405	$3,819,364
1845-3	Underground Conductors and Devices - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		$927,080	$582,853	$1,233,284	$0	$0	$0	$1,477,117	$1,132,322	$121,805	$14,993	$171,801	$19,172	$17,022	$1,477,117
1845-5	Underground Conductors and Devices - Secondary		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Total	$2,743,217	$927,080	$582,853	$1,233,284	$0	$0	$0	$1,477,117	$1,132,322	$121,805	$14,993	$171,801	$19,172	$17,022	$4,220,334
1840 & 1845	Total	$5,225,804	$1,766,080	$1,110,329	$2,349,395	$0	$0	$0	$2,813,894	$2,157,064	$232,038	$28,562	$327,280	$36,523	$32,427	$8,039,698
1850	Line Transformers	$6,098,311	$2,199,391	$1,382,751	$2,516,170	$0	$0	$0	$2,613,562	$2,006,250	$215,815	$22,970	$304,398	$33,969	$30,160	$8,711,874
1815- 1850	Total	$17,399,961	$6,806,182	$3,727,764	$6,866,016	$0	$0	$0	$8,465,621	$6,462,669	$662,218	$163,672	$972,156	$108,433	$96,473	$25,865,583
1855	Services	$0	$0	$0	$0	$0	$0	$0	$2,394,181	$2,191,293	$183,253	$19,634	$0	$0	$0	$2,394,181
1815- 1855	Total	$17,399,961	$6,806,182	$3,727,764	$6,866,016	$0	$0	$0	$10,859,802	$8,653,962	$845,472	$183,306	$972,156	$108,433	$96,473	$28,259,763
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$1,865,032	$944,496	$425,644	$494,892	$0	$0	$0	$1,865,032
1815-1860	Total	$17,399,961	$6,806,182	$3,727,764	$6,866,016	$0	$0	$0	$12,724,834	$9,598,457	$1,271,116	$678,199	$972,156	$108,433	$96,473	$30,124,795
1565-1860	Total	$17,478,201	$6,835,119	$3,741,667	$6,900,787	$502	$36	$88	$12,724,834	$9,598,457	$1,271,116	$678,199	$972,156	$108,433	$96,473	$30,203,034
	Total Demand And Customer	$30,203,034	$16,433,577	$5,012,783	$7,578,986	$972,658	$108,469	$96,561								
	Accum Depreciation - NFA	($18,526,836)	($10,236,424)	($3,047,628)	($4,537,700)	($582,336)	($64,946)	($57,802)								
	Accum Depreciation - NFA ECC	($14,837,942)	($8,265,462)	($2,427,938)	($3,579,973)	($466,273)	($51,994)	($46,302)								
NFA	Net Fixed Assets	$11,676,198	$6,197,153	$1,965,155	$3,041,286	$390,322	$43,523	$38,759								

NFA ECC	Net Fixed Assets Excluding Capital Contribution	$15,365,092	$8,168,115	$2,584,845	$3,999,013	$506,385	$56,475	$50,259

Operating and Maintenance

Allocate all the costs to the O and M expenses before using it as a composite allocator.

Acccounts

5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$1,013	$342	$215	$456	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$66,355	$22,425	$14,098	$29,832	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$2,442	$1,189	$493	$761	$0	$0	$0	$1,126	$1,031	$85	$9	$157	$17	$16
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$702	$342	$142	$219	$0	$0	$0	$324	$296	$25	$3	$45	$5	$4
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$2,490	$898	$565	$1,027	$0	$0	$0	$917	$819	$88	$9	$124	$14	$12
5040	Underground Distribution Lines and Feeders - Operation Labour	$970	$328	$206	$436	$0	$0	$0	$449	$400	$43	$5	$61	$7	$6
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$176	$59	$37	$79	$0	$0	$0	$81	$72	$8	$1	$11	$1	$1
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$486	$175	$110	$200	$0	$0	$0	$179	$160	$17	$2	$24	$3	$2
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	$103,931	$52,633	$23,720	$27,579	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$38,407	$34,267	$3,686	$454	$5,199	$580	$515
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$16,759	$14,952	$1,608	$198	$2,269	$253	$225
5085	Miscellaneous Distribution Expense	$101,571	$39,731	$21,761	$40,080	$0	$0	$0	$48,764	$43,583	$4,258	$923	$4,896	$546	$486
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$83,571	$32,690	$17,904	$32,977	$0	$0	$0	$40,122	$35,859	$3,503	$760	$4,028	$449	$400
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$11,345	$3,834	$2,411	$5,101	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$15,193	$8,306	$3,002	$3,886	$0	$0	$0	$6,992	$6,475	$473	$44	$982	$110	$97
5125	Maintenance of Overhead Conductors and Devices	$44,938	$18,865	$9,285	$16,788	$0	$0	$0	$20,747	$18,786	$1,761	$200	$2,850	$318	$282
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$19,169	$17,545	$1,467	$157	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$67,760	$32,981	$13,677	$21,102	$0	$0	$0	$31,229	$28,617	$2,367	$245	$4,342	$485	$430
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$6,976	$2,358	$1,482	$3,136	$0	$0	$0	$3,227	$2,880	$310	$38	$437	$49	$43
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$80,437	$73,620	$6,157	$660	$0	$0	$0
5160	Maintenance of Line Transformers	$31,789	$11,465	$7,208	$13,116	$0	$0	$0	$11,703	$10,458	$1,125	$120	$1,587	$177	$157
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$25,931	$19,827	$4,266	$1,838	$8	$91	$63
5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0	$114,976	$82,192	$20,003	$12,780	$0	$0	$0
5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0	$236,933	$181,165	$38,976	$16,792	$72	$830	$577
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$159,477	$121,940	$26,234	$11,302	$49	$558	$388
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0	$20,000	$20,000	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M DC	Total	$437,778	$175,986	$92,596	$169,196	$0	$0	$0	$981,879	$767,580	$140,181	$74,118	$27,141	$4,493	$3,707
O&M	Total Demand and Customer	$1,454,997	$943,566	$232,777	$243,314	$27,141	$4,493	$3,707							

Accounts

4705	Power Purchased	$15,828,613	$5,398,148	$2,476,025	$7,807,895	$114,330	$8,257	$23,958	$15,828,613
4708	Charges-WMS	$1,694,433	$577,865	$265,055	$835,825	$12,239	$884	$2,565	$1,694,433
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$205,513	$70,088	$32,148	$101,375	$1,484	$107	$311	$205,513
4714	Charges-NW	$1,235,637	$421,398	$193,287	$609,512	$8,925	$645	$1,870	$1,235,637
4716	Charges-CN	$702,316	$239,516	$109,861	$346,437	$5,073	$366	$1,063	$702,316
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power	$19,666,513	$6,707,015	$3,076,377	$9,701,044	$142,051	$10,258	$29,767	$19,666,513

Acccounts									
5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$1,013	$342	$215	$456	$0	$0	$0	$1,013
5017	Distribution Station Equipment - Operation Supplies and Expenses	$66,355	$22,425	$14,098	$29,832	$0	$0	$0	$66,355
5020	Overhead Distribution Lines and Feeders - Operation Labour	$3,758	$2,220	$578	$769	$157	$17	$16	$3,758
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$1,080	$638	$166	$221	$45	$5	$4	$1,080
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$3,558	$1,717	$653	$1,037	$124	$14	$12	$3,558
5040	Underground Distribution Lines and Feeders - Operation Labour	$1,492	$728	$249	$441	$61	$7	$6	$1,492
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$270	$132	$45	$80	$11	$1	$1	$270
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$694	$335	$127	$202	$24	$3	$2	$694
5065	Meter Expense	$103,931	$52,633	$23,720	$27,579	$0	$0	$0	$103,931
5070	Customer Premises - Operation Labour	$44,701	$34,267	$3,686	$454	$5,199	$580	$515	$44,701
5075	Customer Premises - Materials and Expenses	$19,505	$14,952	$1,608	$198	$2,269	$253	$225	$19,505
5085	Miscellaneous Distribution Expense	$156,263	$83,314	$26,019	$41,003	$4,896	$546	$486	$156,263
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$6,325	$4,102	$1,012	$1,058	$118	$20	$16	$6,325
5105	Maintenance Supervision and Engineering	$128,570	$68,549	$21,408	$33,737	$4,028	$449	$400	$128,570
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$11,345	$3,834	$2,411	$5,101	$0	$0	$0	$11,345
5120	Maintenance of Poles, Towers and Fixtures	$23,374	$14,781	$3,474	$3,930	$982	$110	$97	$23,374
5125	Maintenance of Overhead Conductors and Devices	$69,136	$37,651	$11,047	$16,988	$2,850	$318	$282	$69,136
5130	Maintenance of Overhead Services	$19,169	$17,545	$1,467	$157	$0	$0	$0	$19,169
5135	Overhead Distribution Lines and Feeders - Right of Way	$104,245	$61,597	$16,044	$21,348	$4,342	$485	$430	$104,245
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$10,732	$5,237	$1,792	$3,174	$437	$49	$43	$10,732
5155	Maintenance of Underground Services	$80,437	$73,620	$6,157	$660	$0	$0	$0	$80,437
5160	Maintenance of Line Transformers	$45,413	$21,923	$8,333	$13,236	$1,587	$177	$157	$45,413
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$26,093	$19,827	$4,266	$1,838	$8	$91	$63	$26,093
5310	Meter Reading Expense	$114,976	$82,192	$20,003	$12,780	$0	$0	$0	$114,976
5315	Customer Billing	$238,412	$181,165	$38,976	$16,792	$72	$830	$577	$238,412
5320	Collecting	$160,472	$121,940	$26,234	$11,302	$49	$558	$388	$160,472
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$20,000	$20,000	$0	$0	$0	$0	$0	$20,000
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$28,862	$18,717	$4,617	$4,826	$538	$89	$74	$28,862
5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$386,005	$250,324	$61,755	$64,550	$7,200	$1,192	$983	$386,005
5610	Management Salaries and Expenses	$132,149	$85,699	$21,142	$22,099	$2,465	$408	$337	$132,149
5615	General Administrative Salaries and Expenses	$270,196	$175,222	$43,227	$45,184	$5,040	$834	$688	$270,196
5620	Office Supplies and Expenses	$53,799	$34,888	$8,607	$8,997	$1,004	$166	$137	$53,799
5625	Administrative Expense Transferred Credit	$0	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$123,329	$79,979	$19,731	$20,624	$2,301	$381	$314	$123,329
5635	Property Insurance	$26,412	$14,041	$4,443	$6,874	$870	$97	$86	$26,412
5640	Injuries and Damages	$20,253	$13,134	$3,240	$3,387	$378	$63	$52	$20,253
5645	Employee Pensions and Benefits	$37,330	$24,209	$5,972	$6,243	$696	$115	$95	$37,330
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$77,072	$49,981	$12,330	$12,888	$1,438	$238	$196	$77,072
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$74,656	$48,414	$11,944	$12,484	$1,393	$231	$190	$74,656
5670	Rent	$0	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$77,632	$50,344	$12,420	$12,982	$1,448	$240	$198	$77,632
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0
	OM&A Expenses	**$2,769,015**	**$1,792,620**	**$443,217**	**$465,509**	**$52,029**	**$8,566**	**$7,073**	**$2,769,015**

	Demand Allocators								Customer Allocators						
Grouping of Operating and Maintenance Distribution Costs (lines 106 - 148)	Demand Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 78,713	$ 26,602	$ 16,724	$ 35,388	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ 15,193	$ 8,306	$ 3,002	$ 3,886	$ -	$ -	$ -	$ 6,992	$ 6,475	$ 473	$ 44	$ 982	$ 110	$ 97	$ -
1835	$ 44,938	$ 18,865	$ 9,285	$ 16,788	$ -	$ -	$ -	$ 20,747	$ 18,786	$ 1,761	$ 200	$ 2,850	$ 318	$ 282	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 6,976	$ 2,358	$ 1,482	$ 3,136	$ -	$ -	$ -	$ 3,227	$ 2,880	$ 310	$ 38	$ 437	$ 49	$ 43	$ -
1850	$ 34,765	$ 12,538	$ 7,883	$ 14,344	$ -	$ -	$ -	$ 12,799	$ 11,437	$ 1,230	$ 131	$ 1,735	$ 194	$ 172	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 99,606	$ 91,165	$ 7,624	$ 817	$ -	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 185,142	$ 72,420	$ 39,665	$ 73,057	$ -	$ -	$ -	$ 88,886	$ 79,442	$ 7,761	$ 1,683	$ 8,924	$ 995	$ 886	$ -
1830 & 1835	$ 70,904	$ 34,511	$ 14,311	$ 22,082	$ -	$ -	$ -	$ 32,679	$ 29,945	$ 2,477	$ 257	$ 4,543	$ 507	$ 450	$ -
1840 & 1845	$ 1,146	$ 387	$ 243	$ 515	$ -	$ -	$ -	$ 530	$ 473	$ 51	$ 6	$ 72	$ 8	$ 7	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,166	$ 49,219	$ 5,295	$ 652	$ 7,468	$ 833	$ 740	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 103,931	$ 52,633	$ 23,720	$ 27,579	$ -	$ -	$ -	$ -
CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 114,976	$ 82,192	$ 20,003	$ 12,780	$ -	$ -	$ -	$ -
CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 422,341	$ 322,933	$ 69,477	$ 29,932	$ 129	$ 1,479	$ 1,029	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 437,778**	**$ 175,986**	**$ 92,596**	**$ 169,196**	**$ -**	**$ -**	**$ -**	**$ 981,879**	**$ 767,580**	**$ 140,181**	**$ 74,118**	**$ 27,141**	**$ 4,493**	**$ 3,707**	**$ -**

	Demand Allocators								Customer Allocators						
Grouping of OM&A (lines 168 - 240)	Demand Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 78,713	$ 26,602	$ 16,724	$ 35,388	$ -	$ -	$ -	$ 78,713	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ 23,374	$ 14,781	$ 3,474	$ 3,930	$ 982	$ 110	$ 97	$ 23,374	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 69,136	$ 37,651	$ 11,047	$ 16,988	$ 2,850	$ 318	$ 282	$ 69,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 10,732	$ 5,237	$ 1,792	$ 3,174	$ 437	$ 49	$ 43	$ 10,732	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ 49,665	$ 23,976	$ 9,113	$ 14,475	$ 1,735	$ 194	$ 172	$ 49,665	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 99,606	$ 91,165	$ 7,624	$ 817	$ -	$ -	$ -	$ 99,606	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 284,833	$ 151,862	$ 47,426	$ 74,740	$ 8,924	$ 995	$ 886	$ 284,833	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ 109,083	$ 64,456	$ 16,788	$ 22,338	$ 4,543	$ 507	$ 450	$ 109,083	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ 1,762	$ 860	$ 294	$ 521	$ 72	$ 8	$ 7	$ 1,762	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 20,000	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ 64,207	$ 49,219	$ 5,295	$ 652	$ 7,468	$ 833	$ 740	$ 64,207	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ 103,931	$ 52,633	$ 23,720	$ 27,579	$ -	$ -	$ -	$ 103,931	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMR	$ 114,976	$ 82,192	$ 20,003	$ 12,780	$ -	$ -	$ -	$ 114,976	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ 424,977	$ 322,933	$ 69,477	$ 29,932	$ 129	$ 1,479	$ 1,029	$ 424,977	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 26,412	$ 14,041	$ 4,443	$ 6,874	$ 870	$ 97	$ 86	$ 26,412	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 1,287,607	$ 835,014	$ 205,997	$ 215,322	$ 24,018	$ 3,976	$ 3,280	$ 1,287,607	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 2,769,015**	**$ 1,792,620**	**$ 443,217**	**$ 465,509**	**$ 52,029**	**$ 8,566**	**$ 7,073**	**$ 2,769,015**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Ontario

2010 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet O7 Amortization Output Worksheet - Second Run

Categorization and Allocation of Contributed Capital

Contributed Capital - 1995

	A	B	C	D	E	F	G	H	I	M	N	O	AA
15							Demand Allocation						
16							1	2	3	7	8	9	Sub -total
17	Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Total
18	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	1810-1	Leasehold Improvements >50 kV (Wholesale)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	1810-2	Leasehold Improvements <50 kV (Other)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
40	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
41	1830-4	Poles, Towers and Fixtures - Primary	($12,810)	($8,327)	($4,484)	($12,810)	($2,814)	($1,769)	($3,743)	$0	$0	$0	($8,327)
42	1830-5	Poles, Towers and Fixtures - Secondary	($13,333)	($8,667)	($4,667)	($13,333)	($6,476)	($1,588)	($603)	$0	$0	$0	($8,667)
43	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
45	1835-4	Overhead Conductors and Devices - Primary	($19,153)	($12,449)	($6,704)	($19,153)	($4,207)	($2,645)	($5,597)	$0	$0	$0	($12,449)
46	1835-5	Overhead Conductors and Devices - Secondary	($4,788)	($3,112)	($1,676)	($4,788)	($2,325)	($570)	($217)	$0	$0	$0	($3,112)
47	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
48	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
49	1840-4	Underground Conduit - Primary	($643,941)	($418,561)	($225,379)	($643,941)	($141,454)	($88,932)	($188,175)	$0	$0	$0	($418,561)
50	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
52	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
53	1845-4	Underground Conductors and Devices - Primary	($629,980)	($409,487)	($220,493)	($629,980)	($138,388)	($87,004)	($184,096)	$0	$0	$0	($409,487)
54	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
55	1850	Line Transformers	($1,777,828)	($1,244,479)	($533,348)	($1,777,828)	($448,829)	($282,177)	($513,474)	$0	$0	$0	($1,244,479)
56	1855	Services	($401,655)	$0	($401,655)	($401,655)	$0	$0	$0	$0	$0	$0	$0
57	1860	Meters	($185,405)	$0	($185,405)	($185,405)	$0	$0	$0	$0	$0	$0	$0
58		**Sub - Total**	**($3,688,894)**	**($2,105,083)**	**($1,583,811)**	**($3,688,894)**	**($744,493)**	**($464,686)**	**($895,904)**	**$0**	**$0**	**$0**	**($2,105,083)**

General Plant												
1905	Land	$0										
1906	Land Rights	$0										
1908	Buildings and Fixtures	$0										
1910	Leasehold Improvements	$0										
1915	Office Furniture and Equipment	$0										
1920	Computer Equipment - Hardware	$0										
1925	Computer Software	$0										
1930	Transportation Equipment	$0										
1935	Stores Equipment	$0										
1940	Tools, Shop and Garage Equipment	$0										
1945	Measurement and Testing Equipment	$0										
1950	Power Operated Equipment	$0										
1955	Communication Equipment	$0										
1960	Miscellaneous Equipment	$0										
1970	Load Management Controls - Customer Premises	$0										
1975	Load Management Controls - Utility Premises	$0										
1980	System Supervisory Equipment	$0										
1990	Other Tangible Property	$0										
2005	Property Under Capital Leases	$0										
2010	Electric Plant Purchased or Sold	$0										
	Sub - Total	$0										
	TOTAL - 1995	($3,688,894)	($2,105,083)	($1,583,811)	($3,688,894)	($744,493)	($464,686)	($895,904)	$0	$0	$0	($2,105,083)

Accumulated Depreciation - 2105 Capital Contribution

						Demand Allocation 1	**2**	**3**	**7**	**8**	**9**	**Sub -total**
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$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	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$3,148	$2,046	$1,102	$3,148	$692	$435	$920	$0	$0	$0	$2,046
1830-5	Poles, Towers and Fixtures - Secondary	$3,277	$2,130	$1,147	$3,277	$1,591	$390	$148	$0	$0	$0	$2,130
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$3,608	$2,345	$1,263	$3,608	$793	$498	$1,054	$0	$0	$0	$2,345
1835-5	Overhead Conductors and Devices - Secondary	$902	$586	$316	$902	$438	$107	$41	$0	$0	$0	$586
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$169,329	$110,064	$59,265	$169,329	$37,197	$23,385	$49,482	$0	$0	$0	$110,064
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	M	N	O	AA
121	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
122	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
123	1845-4	Underground Conductors and Devices - Primary	$155,515	$101,085	$54,430	$155,515	$34,162	$21,478	$45,445	$0	$0	$0	$101,085
124	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
125	1850	Line Transformers	$400,057	$280,040	$120,017	$400,057	$100,998	$63,497	$115,545	$0	$0	$0	$280,040
126	1855	Services	$111,863	$0	$111,863	$111,863	$0	$0	$0	$0	$0	$0	$0
127	1860	Meters	$60,838	$0	$60,838	$60,838	$0	$0	$0	$0	$0	$0	$0
128		**Sub - Total**	**$908,538**	**$498,297**	**$410,241**	**$908,538**	**$175,870**	**$109,791**	**$212,636**	**$0**	**$0**	**$0**	**$498,297**
129	**General Plant**												
130	1905	Land	$0										
131	1906	Land Rights	$0										
132	1908	Buildings and Fixtures	$0										
133	1910	Leasehold Improvements	$0										
134	1915	Office Furniture and Equipment	$0										
135	1920	Computer Equipment - Hardware	$0										
136	1925	Computer Software	$0										
137	1930	Transportation Equipment	$0										
138	1935	Stores Equipment	$0										
139	1940	Tools, Shop and Garage Equipment	$0										
140	1945	Measurement and Testing Equipment	$0										
141	1950	Power Operated Equipment	$0										
142	1955	Communication Equipment	$0										
143	1960	Miscellaneous Equipment	$0										
144	1970	Load Management Controls - Customer Premises	$0										
145	1975	Load Management Controls - Utility Premises	$0										
146	1980	System Supervisory Equipment	$0										
147	1990	Other Tangible Property	$0										
148	2005	Property Under Capital Leases	$0										
149	2010	Electric Plant Purchased or Sold	$0										
150		**Sub - Total**	**$0**										
151													
152	**TOTAL - 2105 CC**		$908,538	$498,297	$410,241	$908,538	$175,870	$109,791	$212,636	$0	$0	$0	$498,297
153													
154	**Accumulated Depreciation - 2105 Fixed Assets Only**												
155							**Demand Allocation**						
156							**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
157	**Account**	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
158	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
159	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
160	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
161	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
162	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
163	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
164	1806-2	Land Rights Station <50 kV	($10,634)	($10,634)	$0	($10,634)	($3,933)	($1,890)	($4,726)	($68)	($5)	($12)	($10,634)
165	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
166	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
167	1808-2	Buildings and Fixtures < 50 KV	($15,296)	($15,296)	$0	($15,296)	($5,658)	($2,718)	($6,798)	($98)	($7)	($17)	($15,296)
168	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
169	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
170	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
171	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
172	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
173	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
174	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($472,576)	($472,576)	$0	($472,576)	($159,709)	($100,408)	($212,459)	$0	$0	$0	($472,576)
175	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($113,674)	$0	($113,674)	($113,674)	$0	$0	$0	$0	$0	$0	$0
176	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
177	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
178	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
179	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
180	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
181	1830-4	Poles, Towers and Fixtures - Primary	($1,401,345)	($910,874)	($490,471)	($1,401,345)	($307,833)	($193,534)	($409,507)	$0	$0	$0	($910,874)
182	1830-5	Poles, Towers and Fixtures - Secondary	($1,458,543)	($948,053)	($510,490)	($1,458,543)	($708,369)	($173,714)	($65,970)	$0	$0	$0	($948,053)

	A	B	C	D	E	F	G	H	I	M	N	O	AA
183	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
184	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
185	1835-4	Overhead Conductors and Devices - Primary	($1,580,684)	($1,027,444)	($553,239)	($1,580,684)	($347,229)	($218,302)	($461,914)	$0	$0	$0	($1,027,444)
186	1835-5	Overhead Conductors and Devices - Secondary	($395,171)	($256,861)	($138,310)	($395,171)	($191,922)	($47,065)	($17,874)	$0	$0	$0	($256,861)
187	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
188	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
189	1840-4	Underground Conduit - Primary	($1,742,963)	($1,132,926)	($610,037)	($1,742,963)	($382,876)	($240,713)	($509,336)	$0	$0	$0	($1,132,926)
190	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
191	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
192	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
193	1845-4	Underground Conductors and Devices - Primary	($2,012,538)	($1,308,150)	($704,388)	($2,012,538)	($442,094)	($277,943)	($588,113)	$0	$0	$0	($1,308,150)
194	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
195	1850	Line Transformers	($3,961,150)	($2,772,805)	($1,188,345)	($3,961,150)	($1,000,028)	($628,715)	($1,144,062)	$0	$0	$0	($2,772,805)
196	1855	Services	($1,496,772)	$0	($1,496,772)	($1,496,772)	$0	$0	$0	$0	$0	$0	$0
197	1860	Meters	($1,085,136)	$0	($1,085,136)	($1,085,136)	$0	$0	$0	$0	$0	$0	$0
198		**Sub - Total**	**($15,746,480)**	**($8,855,619)**	**($6,890,861)**	**($15,746,480)**	**($3,549,650)**	**($1,885,003)**	**($3,420,758)**	**($166)**	**($12)**	**($29)**	**($8,855,619)**
199	**General Plant**												
200	1905	Land	$0										
201	1906	Land Rights	($4,938)										
202	1908	Buildings and Fixtures	($827,219)										
203	1910	Leasehold Improvements	$0										
204	1915	Office Furniture and Equipment	($148,709)										
205	1920	Computer Equipment - Hardware	($193,162)										
206	1925	Computer Software	($459,862)										
207	1930	Transportation Equipment	($839,610)										
208	1935	Stores Equipment	($25,186)										
209	1940	Tools, Shop and Garage Equipment	($138,167)										
210	1945	Measurement and Testing Equipment	($14,242)										
211	1950	Power Operated Equipment	$0										
212	1955	Communication Equipment	($16,321)										
213	1960	Miscellaneous Equipment	($7,414)										
214	1970	Load Management Controls - Customer Premises	($550)										
215	1975	Load Management Controls - Utility Premises	$0										
216	1980	System Supervisory Equipment	($250)										
217	1990	Other Tangible Property	$0										
218	2005	Property Under Capital Leases	$0										
219	2010	Electric Plant Purchased or Sold	$0										
220		**Sub - Total**	**($2,675,631)**										
221													
222		**TOTAL - 2105 FA**	($18,422,111)	($8,855,619)	($6,890,861)	($15,746,480)	($3,549,650)	($1,885,003)	($3,420,758)	($166)	($12)	($29)	($8,855,619)
223													
224	**Accumulated Depreciation - 2120**												
225							**Demand Allocation**						
226							**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
227	**Account**	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
228	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
229	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
230	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
231	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
232	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
233	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
234	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
235	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
236	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
237	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
238	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
239	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
240	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
241	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
242	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
243	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	M	N	O	AA
244	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
245	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
246	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
247	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
248	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
249	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
250	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
251	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
252	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
253	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
254	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
256	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
257	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
258	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
259	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
260	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
261	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
262	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
263	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
264	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
265	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
266	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
267	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
268		**Sub - Total**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
269	**General Plant**												
270	1905	Land	$0										
271	1906	Land Rights	$0										
272	1908	Buildings and Fixtures	$0										
273	1910	Leasehold Improvements	$0										
274	1915	Office Furniture and Equipment	$0										
275	1920	Computer Equipment - Hardware	$0										
276	1925	Computer Software	$0										
277	1930	Transportation Equipment	$0										
278	1935	Stores Equipment	$0										
279	1940	Tools, Shop and Garage Equipment	$0										
280	1945	Measurement and Testing Equipment	$0										
281	1950	Power Operated Equipment	$0										
282	1955	Communication Equipment	$0										
283	1960	Miscellaneous Equipment	$0										
284	1970	Load Management Controls - Customer Premises	$0										
285	1975	Load Management Controls - Utility Premises	$0										
286	1980	System Supervisory Equipment	$0										
287	1990	Other Tangible Property	$0										
288	2005	Property Under Capital Leases	$0										
289	2010	Electric Plant Purchased or Sold	$0										
290		**Sub - Total**	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
291													
292		**TOTAL - 2120**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
293													
294													
295	**Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705**												
296													
297													
298							**Demand Allocation**						
299							**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
300	**Account**	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
301	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
302	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
304	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
305	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	M	N	O	AA
306	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
307	1806-2	Land Rights Station <50 kV	$1,353	$1,353	$0	$1,353	$500	$240	$601	$9	$1	$2	$1,353
308	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
309	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
310	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
311	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
312	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
313	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
314	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
315	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
316	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
317	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$21,904	$21,904	$0	$21,904	$7,402	$4,654	$9,847	$0	$0	$0	$21,904
318	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$5,269	$0	$5,269	$5,269	$0	$0	$0	$0	$0	$0	$0
319	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
320	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
321	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
322	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
323	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
324	1830-4	Poles, Towers and Fixtures - Primary	$71,806	$46,674	$25,132	$71,806	$15,774	$9,917	$20,984	$0	$0	$0	$46,674
325	1830-5	Poles, Towers and Fixtures - Secondary	$74,737	$48,579	$26,158	$74,737	$36,298	$8,901	$3,380	$0	$0	$0	$48,579
326	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
327	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
328	1835-4	Overhead Conductors and Devices - Primary	$103,599	$67,339	$36,260	$103,599	$22,758	$14,308	$30,274	$0	$0	$0	$67,339
329	1835-5	Overhead Conductors and Devices - Secondary	$25,900	$16,835	$9,065	$25,900	$12,579	$3,085	$1,171	$0	$0	$0	$16,835
330	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
331	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
332	1840-4	Underground Conduit - Primary	$112,301	$72,996	$39,305	$112,301	$24,669	$15,509	$32,817	$0	$0	$0	$72,996
333	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
334	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
335	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
336	1845-4	Underground Conductors and Devices - Primary	$129,871	$84,416	$45,455	$129,871	$28,529	$17,936	$37,952	$0	$0	$0	$84,416
337	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
338	1850	Line Transformers	$257,263	$180,084	$77,179	$257,263	$64,948	$40,833	$74,303	$0	$0	$0	$180,084
339	1855	Services	$78,265	$0	$78,265	$78,265	$0	$0	$0	$0	$0	$0	$0
340	1860	Meters	$56,581	$0	$56,581	$56,581	$0	$0	$0	$0	$0	$0	$0
341		**Sub - Total**	**$938,849**	**$540,180**	**$398,669**	**$938,849**	**$213,457**	**$115,383**	**$211,330**	**$9**	**$1**	**$2**	**$540,180**
342													
343	**General Plant**												
344	1905	Land	$0										
345	1906	Land Rights	$0										
346	1908	Buildings and Fixtures	$47,061										
347	1910	Leasehold Improvements	$0										
348	1915	Office Furniture and Equipment	$10,545										
349	1920	Computer Equipment - Hardware	$24,396										
350	1925	Computer Software	$93,877										
351	1930	Transportation Equipment	$0										
352	1935	Stores Equipment	$0										
353	1940	Tools, Shop and Garage Equipment	$0										
354	1945	Measurement and Testing Equipment	$0										
355	1950	Power Operated Equipment	$0										
356	1955	Communication Equipment	$0										
357	1960	Miscellaneous Equipment	$3,434										
358	1970	Load Management Controls - Customer Premises	$1,100										
359	1975	Load Management Controls - Utility Premises	$0										
360	1980	System Supervisory Equipment	$500										
361	1990	Other Tangible Property	$0										
362	2005	Property Under Capital Leases	$0										
363	2010	Electric Plant Purchased or Sold	$0										
364		**Sub - Total**	**$180,913**				$0	$0	$0	$0	$0	$0	$0
365													
366		**TOTAL - 5705**	$1,119,762	$540,180	$398,669	$938,849	$213,457	$115,383	$211,330	$9	$1	$2	$540,180
367													

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Demand Allocation 1	2	3	7	8	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$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	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant												
1905	Land	$0										
1906	Land Rights	$0										
1908	Buildings and Fixtures	$0										
1910	Leasehold Improvements	$0										
1915	Office Furniture and Equipment	$0										
1920	Computer Equipment - Hardware	$0										
1925	Computer Software	$0										
1930	Transportation Equipment	$0										
1935	Stores Equipment	$0										
1940	Tools, Shop and Garage Equipment	$0										
1945	Measurement and Testing Equipment	$0										
1950	Power Operated Equipment	$0										
1955	Communication Equipment	$0										

	A	B	C	D	E	F	G	H	I	M	N	O	AA
429	1960	Miscellaneous Equipment	$0										
430	1970	Load Management Controls - Customer Premises	$0										
431	1975	Load Management Controls - Utility Premises	$0										
432	1980	System Supervisory Equipment	$0										
433	1990	Other Tangible Property	$0										
434	2005	Property Under Capital Leases	$0										
435	2010	Electric Plant Purchased or Sold	$0										
436		**Sub - Total**	**$0**				$0	$0	$0	$0	$0	$0	$0
437													
438		**TOTAL - 5710**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
439													
440													

441 **Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715**

442

443

444 445							**Demand Allocation** **1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
446	**Account**	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
447	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
448	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
449	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
450	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
451	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
452	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
453	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
454	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
455	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
456	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
457	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
458	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
459	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
460	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
461	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
462	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
463	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
464	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
465	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
466	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
467	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
468	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
469	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
470	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
471	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
472	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
473	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
474	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
475	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
476	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
477	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
478	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
479	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
480	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
481	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
482	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
483	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
484	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
485	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
486	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
487		**Sub - Total**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

	A	B	C	D	E	F	G	H	I	M	N	O	AA
488	**General Plant**												
489	1905	Land	$0										
490	1906	Land Rights	$0										
491	1908	Buildings and Fixtures	$0										
492	1910	Leasehold Improvements	$0										
493	1915	Office Furniture and Equipment	$0										
494	1920	Computer Equipment - Hardware	$0										
495	1925	Computer Software	$0										
496	1930	Transportation Equipment	$0										
497	1935	Stores Equipment	$0										
498	1940	Tools, Shop and Garage Equipment	$0										
499	1945	Measurement and Testing Equipment	$0										
500	1950	Power Operated Equipment	$0										
501	1955	Communication Equipment	$0										
502	1960	Miscellaneous Equipment	$0										
503	1970	Load Management Controls - Customer Premises	$0										
504	1975	Load Management Controls - Utility Premises	$0										
505	1980	System Supervisory Equipment	$0										
506	1990	Other Tangible Property	$0										
507	2005	Property Under Capital Leases	$0										
508	2010	Electric Plant Purchased or Sold	$0										
509		**Sub - Total**	**$0**				$0	$0	$0	$0	$0	$0	$0
510													
511		**TOTAL - 5715**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512													
513													
514	**Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720**												
515													
516													
517							**Demand Allocation**						
518							**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
519	**Account**	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
520	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
521	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
522	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
523	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
524	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
525	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
526	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
527	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
528	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
529	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
530	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
531	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
532	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
533	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
534	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
535	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
536	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
540	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
541	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
543	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
544	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
545	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
546	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
547	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	A	B	C	D	E	F	G	H	I	M	N	O	AA
550	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
551	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
552	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
553	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
554	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
555	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
556	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
558	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
559	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
560		**Sub - Total**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
561	**General Plant**												
562	1905	Land	$0										
563	1906	Land Rights	$0										
564	1908	Buildings and Fixtures	$0										
565	1910	Leasehold Improvements	$0										
566	1915	Office Furniture and Equipment	$0										
567	1920	Computer Equipment - Hardware	$0										
568	1925	Computer Software	$0										
569	1930	Transportation Equipment	$0										
570	1935	Stores Equipment	$0										
571	1940	Tools, Shop and Garage Equipment	$0										
572	1945	Measurement and Testing Equipment	$0										
573	1950	Power Operated Equipment	$0										
574	1955	Communication Equipment	$0										
575	1960	Miscellaneous Equipment	$0										
576	1970	Load Management Controls - Customer Premises	$0										
577	1975	Load Management Controls - Utility Premises	$0										
578	1980	System Supervisory Equipment	$0										
579	1990	Other Tangible Property	$0										
580	2005	Property Under Capital Leases	$0										
581	2010	Electric Plant Purchased or Sold	$0										
582		**Sub - Total**	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
583													
584		**TOTAL - 5720**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
585													
586							**Demand Allocation**						
587							**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
588	**Account**	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
589	1565	Conservation and Demand Management	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
590	1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
591	1805-1	Land Station >50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
592	1805-2	Land Station <50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
593	1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
594	1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
595	1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
596	1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
597	1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
598	1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
599	1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
600	1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
601	1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
602	1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
603	1820	Distribution Station Equipment - Normally Primary below 50 kV					36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
604	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
605	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%	100.00%
606	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
607	1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
608	1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
609	1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
610	1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
611	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%

	A	B	C	D	E	F	G	H	I	M	N	O	AA
612	1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%	100.00%
613	1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%	74.72%	18.32%	6.96%	0.00%	0.00%	0.00%	100.00%
614	1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
615	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
616	1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%	100.00%
617	1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%	74.72%	18.32%	6.96%	0.00%	0.00%	0.00%	100.00%
618	1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
619	1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
620	1840-4	Underground Conduit - Primary	100%	65%	35%	100%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%	100.00%
621	1840-5	Underground Conduit - Secondary	100%	65%	35%	100%	74.72%	18.32%	6.96%	0.00%	0.00%	0.00%	100.00%
622	1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
623	1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%	100.00%
624	1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%	100.00%
625	1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%	74.72%	18.32%	6.96%	0.00%	0.00%	0.00%	100.00%
626	1850	Line Transformers	100%	70%	30%	100%	36.07%	22.67%	41.26%	0.00%	0.00%	0.00%	100.00%
627	1855	Services	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
628	1860	Meters	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
629	**General Plant**												
630	1905	Land	100%										
631	1906	Land Rights	100%										
632	1908	Buildings and Fixtures	100%										
633	1910	Leasehold Improvements	100%										
634	1915	Office Furniture and Equipment	100%										
635	1920	Computer Equipment - Hardware	100%										
636	1925	Computer Software	100%										
637	1930	Transportation Equipment	100%										
638	1935	Stores Equipment	100%										
639	1940	Tools, Shop and Garage Equipment	100%										
640	1945	Measurement and Testing Equipment	100%										
641	1950	Power Operated Equipment	100%										
642	1955	Communication Equipment	100%										
643	1960	Miscellaneous Equipment	100%										
644	1970	Load Management Controls - Customer Premises	100%										
645	1975	Load Management Controls - Utility Premises	100%										
646	1980	System Supervisory Equipment	100%										
647	1990	Other Tangible Property	100%										
648	2005	Property Under Capital Leases	100%										
649	2010	Electric Plant Purchased or Sold	100%										

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
1														
2														
3														
4														
5														
6														
7														
8														
9														
10														
14														
15	**Customer Allocation**							**A & G Allocation**						
16	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
17	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
18	$0	$0	$0	$0	$0	$0	$0							
19	$0	$0	$0	$0	$0	$0	$0							
20	$0	$0	$0	$0	$0	$0	$0							
21	$0	$0	$0	$0	$0	$0	$0							
22	$0	$0	$0	$0	$0	$0	$0							
23	$0	$0	$0	$0	$0	$0	$0							
24	$0	$0	$0	$0	$0	$0	$0							
25	$0	$0	$0	$0	$0	$0	$0							
26	$0	$0	$0	$0	$0	$0	$0							
27	$0	$0	$0	$0	$0	$0	$0							
28	$0	$0	$0	$0	$0	$0	$0							
29	$0	$0	$0	$0	$0	$0	$0							
30	$0	$0	$0	$0	$0	$0	$0							
31	$0	$0	$0	$0	$0	$0	$0							
32	$0	$0	$0	$0	$0	$0	$0							
33	$0	$0	$0	$0	$0	$0	$0							
34	$0	$0	$0	$0	$0	$0	$0							
35	$0	$0	$0	$0	$0	$0	$0							
36	$0	$0	$0	$0	$0	$0	$0							
37	$0	$0	$0	$0	$0	$0	$0							
38	$0	$0	$0	$0	$0	$0	$0							
39	$0	$0	$0	$0	$0	$0	$0							
40	$0	$0	$0	$0	$0	$0	$0							
41	($3,437)	($370)	($46)	($521)	($58)	($52)	($4,484)							
42	($3,805)	($159)	($3)	($577)	($64)	($57)	($4,667)							
43	$0	$0	$0	$0	$0	$0	$0							
44	$0	$0	$0	$0	$0	$0	$0							
45	($5,139)	($553)	($68)	($780)	($87)	($77)	($6,704)							
46	($1,367)	($57)	($1)	($207)	($23)	($21)	($1,676)							
47	$0	$0	$0	$0	$0	$0	$0							
48	$0	$0	$0	$0	$0	$0	$0							
49	($172,770)	($18,585)	($2,288)	($26,214)	($2,925)	($2,597)	($225,379)							
50	$0	$0	$0	$0	$0	$0	$0							
51	$0	$0	$0	$0	$0	$0	$0							
52	$0	$0	$0	$0	$0	$0	$0							
53	($169,025)	($18,182)	($2,238)	($25,645)	($2,862)	($2,541)	($220,493)							
54	$0	$0	$0	$0	$0	$0	$0							
55	($409,414)	($44,041)	($4,687)	($62,118)	($6,932)	($6,155)	($533,348)							
56	($367,618)	($30,743)	($3,294)	$0	$0	$0	($401,655)							
57	($93,894)	($42,314)	($49,198)	$0	$0	$0	($185,405)							
58	**($1,226,469)**	**($155,004)**	**($61,823)**	**($116,063)**	**($12,952)**	**($11,500)**	**($1,583,811)**							

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
59														
60								$0	$0	$0	$0	$0	$0	$0
61								$0	$0	$0	$0	$0	$0	$0
62								$0	$0	$0	$0	$0	$0	$0
63								$0	$0	$0	$0	$0	$0	$0
64								$0	$0	$0	$0	$0	$0	$0
65								$0	$0	$0	$0	$0	$0	$0
66								$0	$0	$0	$0	$0	$0	$0
67								$0	$0	$0	$0	$0	$0	$0
68								$0	$0	$0	$0	$0	$0	$0
69								$0	$0	$0	$0	$0	$0	$0
70								$0	$0	$0	$0	$0	$0	$0
71								$0	$0	$0	$0	$0	$0	$0
72								$0	$0	$0	$0	$0	$0	$0
73								$0	$0	$0	$0	$0	$0	$0
74								$0	$0	$0	$0	$0	$0	$0
75								$0	$0	$0	$0	$0	$0	$0
76								$0	$0	$0	$0	$0	$0	$0
77								$0	$0	$0	$0	$0	$0	$0
78								$0	$0	$0	$0	$0	$0	$0
79								$0	$0	$0	$0	$0	$0	$0
80								$0	$0	$0	$0	$0	$0	$0
81														
82	($1,226,469)	($155,004)	($61,823)	($116,063)	($12,952)	($11,500)	($1,583,811)	$0	$0	$0	$0	$0	$0	$0
83														
84														
85	**Customer Allocation**							**A & G Allocation**						
86	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
87	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
88	$0	$0	$0	$0	$0	$0	$0							
89	$0	$0	$0	$0	$0	$0	$0							
90	$0	$0	$0	$0	$0	$0	$0							
91	$0	$0	$0	$0	$0	$0	$0							
92	$0	$0	$0	$0	$0	$0	$0							
93	$0	$0	$0	$0	$0	$0	$0							
94	$0	$0	$0	$0	$0	$0	$0							
95	$0	$0	$0	$0	$0	$0	$0							
96	$0	$0	$0	$0	$0	$0	$0							
97	$0	$0	$0	$0	$0	$0	$0							
98	$0	$0	$0	$0	$0	$0	$0							
99	$0	$0	$0	$0	$0	$0	$0							
100	$0	$0	$0	$0	$0	$0	$0							
101	$0	$0	$0	$0	$0	$0	$0							
102	$0	$0	$0	$0	$0	$0	$0							
103	$0	$0	$0	$0	$0	$0	$0							
104	$0	$0	$0	$0	$0	$0	$0							
105	$0	$0	$0	$0	$0	$0	$0							
106	$0	$0	$0	$0	$0	$0	$0							
107	$0	$0	$0	$0	$0	$0	$0							
108	$0	$0	$0	$0	$0	$0	$0							
109	$0	$0	$0	$0	$0	$0	$0							
110	$0	$0	$0	$0	$0	$0	$0							
111	$845	$91	$11	$128	$14	$13	$1,102							
112	$935	$39	$1	$142	$16	$14	$1,147							
113	$0	$0	$0	$0	$0	$0	$0							
114	$0	$0	$0	$0	$0	$0	$0							
115	$968	$104	$13	$147	$16	$15	$1,263							
116	$257	$11	$0	$39	$4	$4	$316							
117	$0	$0	$0	$0	$0	$0	$0							
118	$0	$0	$0	$0	$0	$0	$0							
119	$45,431	$4,887	$602	$6,893	$769	$683	$59,265							
120	$0	$0	$0	$0	$0	$0	$0							

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
121	$0	$0	$0	$0	$0	$0	$0							
122	$0	$0	$0	$0	$0	$0	$0							
123	$41,725	$4,488	$552	$6,331	$706	$627	$54,430							
124	$0	$0	$0	$0	$0	$0	$0							
125	$92,129	$9,910	$1,055	$13,978	$1,560	$1,385	$120,017							
126	$102,384	$8,562	$917	$0	$0	$0	$111,863							
127	$30,810	$13,885	$16,144	$0	$0	$0	$60,838							
128	**$315,484**	**$41,978**	**$19,295**	**$27,658**	**$3,086**	**$2,740**	**$410,241**							
129														
130								$0	$0	$0	$0	$0	$0	$0
131								$0	$0	$0	$0	$0	$0	$0
132								$0	$0	$0	$0	$0	$0	$0
133								$0	$0	$0	$0	$0	$0	$0
134								$0	$0	$0	$0	$0	$0	$0
135								$0	$0	$0	$0	$0	$0	$0
136								$0	$0	$0	$0	$0	$0	$0
137								$0	$0	$0	$0	$0	$0	$0
138								$0	$0	$0	$0	$0	$0	$0
139								$0	$0	$0	$0	$0	$0	$0
140								$0	$0	$0	$0	$0	$0	$0
141								$0	$0	$0	$0	$0	$0	$0
142								$0	$0	$0	$0	$0	$0	$0
143								$0	$0	$0	$0	$0	$0	$0
144								$0	$0	$0	$0	$0	$0	$0
145								$0	$0	$0	$0	$0	$0	$0
146								$0	$0	$0	$0	$0	$0	$0
147								$0	$0	$0	$0	$0	$0	$0
148								$0	$0	$0	$0	$0	$0	$0
149								$0	$0	$0	$0	$0	$0	$0
150								$0	$0	$0	$0	$0	$0	$0
151														
152	$315,484	$41,978	$19,295	$27,658	$3,086	$2,740	$410,241	$0	$0	$0	$0	$0	$0	$0
153														
154														
155	**Customer Allocation**							**A & G Allocation**						
156	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
157	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
158	$0	$0	$0	$0	$0	$0	$0							
159	$0	$0	$0	$0	$0	$0	$0							
160	$0	$0	$0	$0	$0	$0	$0							
161	$0	$0	$0	$0	$0	$0	$0							
162	$0	$0	$0	$0	$0	$0	$0							
163	$0	$0	$0	$0	$0	$0	$0							
164	$0	$0	$0	$0	$0	$0	$0							
165	$0	$0	$0	$0	$0	$0	$0							
166	$0	$0	$0	$0	$0	$0	$0							
167	$0	$0	$0	$0	$0	$0	$0							
168	$0	$0	$0	$0	$0	$0	$0							
169	$0	$0	$0	$0	$0	$0	$0							
170	$0	$0	$0	$0	$0	$0	$0							
171	$0	$0	$0	$0	$0	$0	$0							
172	$0	$0	$0	$0	$0	$0	$0							
173	$0	$0	$0	$0	$0	$0	$0							
174	$0	$0	$0	$0	$0	$0	$0							
175	($38,767)	($17,782)	($56,073)	($821)	($59)	($172)	($113,674)							
176	$0	$0	$0	$0	$0	$0	$0							
177	$0	$0	$0	$0	$0	$0	$0							
178	$0	$0	$0	$0	$0	$0	$0							
179	$0	$0	$0	$0	$0	$0	$0							
180	$0	$0	$0	$0	$0	$0	$0							
181	($375,983)	($40,445)	($4,978)	($57,046)	($6,366)	($5,652)	($490,471)							
182	($416,251)	($17,405)	($373)	($63,156)	($7,048)	($6,258)	($510,490)							

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
183	$0	$0	$0	$0	$0	$0	$0							
184	$0	$0	$0	$0	$0	$0	$0							
185	($424,100)	($45,621)	($5,616)	($64,346)	($7,181)	($6,376)	($553,239)							
186	($112,777)	($4,716)	($101)	($17,111)	($1,909)	($1,695)	($138,310)							
187	$0	$0	$0	$0	$0	$0	$0							
188	$0	$0	$0	$0	$0	$0	$0							
189	($467,640)	($50,305)	($6,192)	($70,953)	($7,918)	($7,030)	($610,037)							
190	$0	$0	$0	$0	$0	$0	$0							
191	$0	$0	$0	$0	$0	$0	$0							
192	$0	$0	$0	$0	$0	$0	$0							
193	($539,967)	($58,085)	($7,150)	($81,926)	($9,143)	($8,117)	($704,388)							
194	$0	$0	$0	$0	$0	$0	$0							
195	($912,210)	($98,128)	($10,444)	($138,405)	($15,445)	($13,713)	($1,188,345)							
196	($1,369,932)	($114,565)	($12,275)	$0	$0	$0	($1,496,772)							
197	($549,538)	($247,653)	($287,944)	$0	$0	$0	($1,085,136)							
198	**($5,207,166)**	**($694,704)**	**($391,145)**	**($493,764)**	**($55,069)**	**($49,014)**	**($6,890,861)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
199														
200								$0	$0	$0	$0	$0	$0	$0
201								($2,625)	($831)	($1,285)	($163)	($18)	($16)	($4,938)
202								($439,752)	($139,162)	($215,297)	($27,263)	($3,040)	($2,706)	($827,219)
203								$0	$0	$0	$0	$0	$0	$0
204								($79,054)	($25,017)	($38,704)	($4,901)	($547)	($486)	($148,709)
205								($102,685)	($32,495)	($50,274)	($6,366)	($710)	($632)	($193,162)
206								($244,464)	($77,362)	($119,687)	($15,156)	($1,690)	($1,504)	($459,862)
207								($446,338)	($141,246)	($218,522)	($27,671)	($3,086)	($2,746)	($839,610)
208								($13,389)	($4,237)	($6,555)	($830)	($93)	($82)	($25,186)
209								($73,450)	($23,244)	($35,960)	($4,554)	($508)	($452)	($138,167)
210								($7,571)	($2,396)	($3,707)	($469)	($52)	($47)	($14,242)
211								$0	$0	$0	$0	$0	$0	$0
212								($8,676)	($2,746)	($4,248)	($538)	($60)	($53)	($16,321)
213								($3,942)	($1,247)	($1,930)	($244)	($27)	($24)	($7,414)
214								($292)	($93)	($143)	($18)	($2)	($2)	($550)
215								$0	$0	$0	$0	$0	$0	$0
216								($133)	($42)	($65)	($8)	($1)	($1)	($250)
217								$0	$0	$0	$0	$0	$0	$0
218								$0	$0	$0	$0	$0	$0	$0
219								$0	$0	$0	$0	$0	$0	$0
220								($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)	($2,675,631)
221														
222	($5,207,166)	($694,704)	($391,145)	($493,764)	($55,069)	($49,014)	($6,890,861)	($1,422,371)	($450,117)	($696,376)	($88,180)	($9,834)	($8,752)	($2,675,631)
223														
224														
225	**Customer Allocation**							**A & G Allocation**						
226	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
227	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
228	$0	$0	$0	$0	$0	$0	$0							
229	$0	$0	$0	$0	$0	$0	$0							
230	$0	$0	$0	$0	$0	$0	$0							
231	$0	$0	$0	$0	$0	$0	$0							
232	$0	$0	$0	$0	$0	$0	$0							
233	$0	$0	$0	$0	$0	$0	$0							
234	$0	$0	$0	$0	$0	$0	$0							
235	$0	$0	$0	$0	$0	$0	$0							
236	$0	$0	$0	$0	$0	$0	$0							
237	$0	$0	$0	$0	$0	$0	$0							
238	$0	$0	$0	$0	$0	$0	$0							
239	$0	$0	$0	$0	$0	$0	$0							
240	$0	$0	$0	$0	$0	$0	$0							
241	$0	$0	$0	$0	$0	$0	$0							
242	$0	$0	$0	$0	$0	$0	$0							
243	$0	$0	$0	$0	$0	$0	$0							

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
244	$0	$0	$0	$0	$0	$0	$0							
245	$0	$0	$0	$0	$0	$0	$0							
246	$0	$0	$0	$0	$0	$0	$0							
247	$0	$0	$0	$0	$0	$0	$0							
248	$0	$0	$0	$0	$0	$0	$0							
249	$0	$0	$0	$0	$0	$0	$0							
250	$0	$0	$0	$0	$0	$0	$0							
251	$0	$0	$0	$0	$0	$0	$0							
252	$0	$0	$0	$0	$0	$0	$0							
253	$0	$0	$0	$0	$0	$0	$0							
254	$0	$0	$0	$0	$0	$0	$0							
255	$0	$0	$0	$0	$0	$0	$0							
256	$0	$0	$0	$0	$0	$0	$0							
257	$0	$0	$0	$0	$0	$0	$0							
258	$0	$0	$0	$0	$0	$0	$0							
259	$0	$0	$0	$0	$0	$0	$0							
260	$0	$0	$0	$0	$0	$0	$0							
261	$0	$0	$0	$0	$0	$0	$0							
262	$0	$0	$0	$0	$0	$0	$0							
263	$0	$0	$0	$0	$0	$0	$0							
264	$0	$0	$0	$0	$0	$0	$0							
265	$0	$0	$0	$0	$0	$0	$0							
266	$0	$0	$0	$0	$0	$0	$0							
267	$0	$0	$0	$0	$0	$0	$0							
268	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
269														
270								$0	$0	$0	$0	$0	$0	$0
271								$0	$0	$0	$0	$0	$0	$0
272								$0	$0	$0	$0	$0	$0	$0
273								$0	$0	$0	$0	$0	$0	$0
274								$0	$0	$0	$0	$0	$0	$0
275								$0	$0	$0	$0	$0	$0	$0
276								$0	$0	$0	$0	$0	$0	$0
277								$0	$0	$0	$0	$0	$0	$0
278								$0	$0	$0	$0	$0	$0	$0
279								$0	$0	$0	$0	$0	$0	$0
280								$0	$0	$0	$0	$0	$0	$0
281								$0	$0	$0	$0	$0	$0	$0
282								$0	$0	$0	$0	$0	$0	$0
283								$0	$0	$0	$0	$0	$0	$0
284								$0	$0	$0	$0	$0	$0	$0
285								$0	$0	$0	$0	$0	$0	$0
286								$0	$0	$0	$0	$0	$0	$0
287								$0	$0	$0	$0	$0	$0	$0
288								$0	$0	$0	$0	$0	$0	$0
289								$0	$0	$0	$0	$0	$0	$0
290	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
291														
292	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
293														
294														
295														
296														
297														
298	**Customer Allocation**							**A & G Allocation**						
299	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
300	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
301	$0	$0	$0	$0	$0	$0	$0							
302	$0	$0	$0	$0	$0	$0	$0							
303	$0	$0	$0	$0	$0	$0	$0							
304	$0	$0	$0	$0	$0	$0	$0							
305	$0	$0	$0	$0	$0	$0	$0							

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
306	$0	$0	$0	$0	$0	$0	$0							
307	$0	$0	$0	$0	$0	$0	$0							
308	$0	$0	$0	$0	$0	$0	$0							
309	$0	$0	$0	$0	$0	$0	$0							
310	$0	$0	$0	$0	$0	$0	$0							
311	$0	$0	$0	$0	$0	$0	$0							
312	$0	$0	$0	$0	$0	$0	$0							
313	$0	$0	$0	$0	$0	$0	$0							
314	$0	$0	$0	$0	$0	$0	$0							
315	$0	$0	$0	$0	$0	$0	$0							
316	$0	$0	$0	$0	$0	$0	$0							
317	$0	$0	$0	$0	$0	$0	$0							
318	$1,797	$824	$2,599	$38	$3	$8	$5,269							
319	$0	$0	$0	$0	$0	$0	$0							
320	$0	$0	$0	$0	$0	$0	$0							
321	$0	$0	$0	$0	$0	$0	$0							
322	$0	$0	$0	$0	$0	$0	$0							
323	$0	$0	$0	$0	$0	$0	$0							
324	$19,266	$2,072	$255	$2,923	$326	$290	$25,132							
325	$21,329	$892	$19	$3,236	$361	$321	$26,158							
326	$0	$0	$0	$0	$0	$0	$0							
327	$0	$0	$0	$0	$0	$0	$0							
328	$27,796	$2,990	$368	$4,217	$471	$418	$36,260							
329	$7,391	$309	$7	$1,121	$125	$111	$9,065							
330	$0	$0	$0	$0	$0	$0	$0							
331	$0	$0	$0	$0	$0	$0	$0							
332	$30,131	$3,241	$399	$4,572	$510	$453	$39,305							
333	$0	$0	$0	$0	$0	$0	$0							
334	$0	$0	$0	$0	$0	$0	$0							
335	$0	$0	$0	$0	$0	$0	$0							
336	$34,845	$3,748	$461	$5,287	$590	$524	$45,455							
337	$0	$0	$0	$0	$0	$0	$0							
338	$59,245	$6,373	$678	$8,989	$1,003	$891	$77,179							
339	$71,633	$5,990	$642	$0	$0	$0	$78,265							
340	$28,654	$12,913	$15,014	$0	$0	$0	$56,581							
341	**$302,086**	**$39,354**	**$20,442**	**$30,383**	**$3,389**	**$3,015**	**$398,669**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
342														
343														
344								$0	$0	$0	$0	$0	$0	$0
345								$0	$0	$0	$0	$0	$0	$0
346								$25,018	$7,917	$12,248	$1,551	$173	$154	$47,061
347								$0	$0	$0	$0	$0	$0	$0
348								$5,606	$1,774	$2,745	$348	$39	$34	$10,545
349								$12,969	$4,104	$6,350	$804	$90	$80	$24,396
350								$49,905	$15,793	$24,433	$3,094	$345	$307	$93,877
351								$0	$0	$0	$0	$0	$0	$0
352								$0	$0	$0	$0	$0	$0	$0
353								$0	$0	$0	$0	$0	$0	$0
354								$0	$0	$0	$0	$0	$0	$0
355								$0	$0	$0	$0	$0	$0	$0
356								$0	$0	$0	$0	$0	$0	$0
357								$1,825	$578	$894	$113	$13	$11	$3,434
358								$585	$185	$286	$36	$4	$4	$1,100
359								$0	$0	$0	$0	$0	$0	$0
360								$266	$84	$130	$16	$2	$2	$500
361								$0	$0	$0	$0	$0	$0	$0
362								$0	$0	$0	$0	$0	$0	$0
363								$0	$0	$0	$0	$0	$0	$0
364	$0	$0	$0	$0	$0	$0	$0	$96,174	$30,435	$47,086	$5,962	$665	$592	$180,913
365														
366	$302,086	$39,354	$20,442	$30,383	$3,389	$3,015	$398,669	$96,174	$30,435	$47,086	$5,962	$665	$592	$180,913
367														

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
368														
369														
370														
371	**Customer Allocation**							**A & G Allocation**						
372	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
373	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
374	$0	$0	$0	$0	$0	$0	$0							
375	$0	$0	$0	$0	$0	$0	$0							
376	$0	$0	$0	$0	$0	$0	$0							
377	$0	$0	$0	$0	$0	$0	$0							
378	$0	$0	$0	$0	$0	$0	$0							
379	$0	$0	$0	$0	$0	$0	$0							
380	$0	$0	$0	$0	$0	$0	$0							
381	$0	$0	$0	$0	$0	$0	$0							
382	$0	$0	$0	$0	$0	$0	$0							
383	$0	$0	$0	$0	$0	$0	$0							
384	$0	$0	$0	$0	$0	$0	$0							
385	$0	$0	$0	$0	$0	$0	$0							
386	$0	$0	$0	$0	$0	$0	$0							
387	$0	$0	$0	$0	$0	$0	$0							
388	$0	$0	$0	$0	$0	$0	$0							
389	$0	$0	$0	$0	$0	$0	$0							
390	$0	$0	$0	$0	$0	$0	$0							
391	$0	$0	$0	$0	$0	$0	$0							
392	$0	$0	$0	$0	$0	$0	$0							
393	$0	$0	$0	$0	$0	$0	$0							
394	$0	$0	$0	$0	$0	$0	$0							
395	$0	$0	$0	$0	$0	$0	$0							
396	$0	$0	$0	$0	$0	$0	$0							
397	$0	$0	$0	$0	$0	$0	$0							
398	$0	$0	$0	$0	$0	$0	$0							
399	$0	$0	$0	$0	$0	$0	$0							
400	$0	$0	$0	$0	$0	$0	$0							
401	$0	$0	$0	$0	$0	$0	$0							
402	$0	$0	$0	$0	$0	$0	$0							
403	$0	$0	$0	$0	$0	$0	$0							
404	$0	$0	$0	$0	$0	$0	$0							
405	$0	$0	$0	$0	$0	$0	$0							
406	$0	$0	$0	$0	$0	$0	$0							
407	$0	$0	$0	$0	$0	$0	$0							
408	$0	$0	$0	$0	$0	$0	$0							
409	$0	$0	$0	$0	$0	$0	$0							
410	$0	$0	$0	$0	$0	$0	$0							
411	$0	$0	$0	$0	$0	$0	$0							
412	$0	$0	$0	$0	$0	$0	$0							
413	$0	$0	$0	$0	$0	$0	$0							
414	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
415														
416								$0	$0	$0	$0	$0	$0	$0
417								$0	$0	$0	$0	$0	$0	$0
418								$0	$0	$0	$0	$0	$0	$0
419								$0	$0	$0	$0	$0	$0	$0
420								$0	$0	$0	$0	$0	$0	$0
421								$0	$0	$0	$0	$0	$0	$0
422								$0	$0	$0	$0	$0	$0	$0
423								$0	$0	$0	$0	$0	$0	$0
424								$0	$0	$0	$0	$0	$0	$0
425								$0	$0	$0	$0	$0	$0	$0
426								$0	$0	$0	$0	$0	$0	$0
427								$0	$0	$0	$0	$0	$0	$0
428								$0	$0	$0	$0	$0	$0	$0

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
429								$0	$0	$0	$0	$0	$0	$0
430								$0	$0	$0	$0	$0	$0	$0
431								$0	$0	$0	$0	$0	$0	$0
432								$0	$0	$0	$0	$0	$0	$0
433								$0	$0	$0	$0	$0	$0	$0
434								$0	$0	$0	$0	$0	$0	$0
435								$0	$0	$0	$0	$0	$0	$0
436	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
437														
438	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
439														
440														
441														
442														
443														
444	**Customer Allocation**							**A & G Allocation**						
445	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
446	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
447	$0	$0	$0	$0	$0	$0	$0							
448	$0	$0	$0	$0	$0	$0	$0							
449	$0	$0	$0	$0	$0	$0	$0							
450	$0	$0	$0	$0	$0	$0	$0							
451	$0	$0	$0	$0	$0	$0	$0							
452	$0	$0	$0	$0	$0	$0	$0							
453	$0	$0	$0	$0	$0	$0	$0							
454	$0	$0	$0	$0	$0	$0	$0							
455	$0	$0	$0	$0	$0	$0	$0							
456	$0	$0	$0	$0	$0	$0	$0							
457	$0	$0	$0	$0	$0	$0	$0							
458	$0	$0	$0	$0	$0	$0	$0							
459	$0	$0	$0	$0	$0	$0	$0							
460	$0	$0	$0	$0	$0	$0	$0							
461	$0	$0	$0	$0	$0	$0	$0							
462	$0	$0	$0	$0	$0	$0	$0							
463	$0	$0	$0	$0	$0	$0	$0							
464	$0	$0	$0	$0	$0	$0	$0							
465	$0	$0	$0	$0	$0	$0	$0							
466	$0	$0	$0	$0	$0	$0	$0							
467	$0	$0	$0	$0	$0	$0	$0							
468	$0	$0	$0	$0	$0	$0	$0							
469	$0	$0	$0	$0	$0	$0	$0							
470	$0	$0	$0	$0	$0	$0	$0							
471	$0	$0	$0	$0	$0	$0	$0							
472	$0	$0	$0	$0	$0	$0	$0							
473	$0	$0	$0	$0	$0	$0	$0							
474	$0	$0	$0	$0	$0	$0	$0							
475	$0	$0	$0	$0	$0	$0	$0							
476	$0	$0	$0	$0	$0	$0	$0							
477	$0	$0	$0	$0	$0	$0	$0							
478	$0	$0	$0	$0	$0	$0	$0							
479	$0	$0	$0	$0	$0	$0	$0							
480	$0	$0	$0	$0	$0	$0	$0							
481	$0	$0	$0	$0	$0	$0	$0							
482	$0	$0	$0	$0	$0	$0	$0							
483	$0	$0	$0	$0	$0	$0	$0							
484	$0	$0	$0	$0	$0	$0	$0							
485	$0	$0	$0	$0	$0	$0	$0							
486	$0	$0	$0	$0	$0	$0	$0							
487	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
488														
489								$0	$0	$0	$0	$0	$0	$0
490								$0	$0	$0	$0	$0	$0	$0
491								$0	$0	$0	$0	$0	$0	$0
492								$0	$0	$0	$0	$0	$0	$0
493								$0	$0	$0	$0	$0	$0	$0
494								$0	$0	$0	$0	$0	$0	$0
495								$0	$0	$0	$0	$0	$0	$0
496								$0	$0	$0	$0	$0	$0	$0
497								$0	$0	$0	$0	$0	$0	$0
498								$0	$0	$0	$0	$0	$0	$0
499								$0	$0	$0	$0	$0	$0	$0
500								$0	$0	$0	$0	$0	$0	$0
501								$0	$0	$0	$0	$0	$0	$0
502								$0	$0	$0	$0	$0	$0	$0
503								$0	$0	$0	$0	$0	$0	$0
504								$0	$0	$0	$0	$0	$0	$0
505								$0	$0	$0	$0	$0	$0	$0
506								$0	$0	$0	$0	$0	$0	$0
507								$0	$0	$0	$0	$0	$0	$0
508								$0	$0	$0	$0	$0	$0	$0
509	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
510														
511	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512														
513														
514														
515														
516														
517	**Customer Allocation**							**A & G Allocation**						
518	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
519	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
520	$0	$0	$0	$0	$0	$0	$0							
521	$0	$0	$0	$0	$0	$0	$0							
522	$0	$0	$0	$0	$0	$0	$0							
523	$0	$0	$0	$0	$0	$0	$0							
524	$0	$0	$0	$0	$0	$0	$0							
525	$0	$0	$0	$0	$0	$0	$0							
526	$0	$0	$0	$0	$0	$0	$0							
527	$0	$0	$0	$0	$0	$0	$0							
528	$0	$0	$0	$0	$0	$0	$0							
529	$0	$0	$0	$0	$0	$0	$0							
530	$0	$0	$0	$0	$0	$0	$0							
531	$0	$0	$0	$0	$0	$0	$0							
532	$0	$0	$0	$0	$0	$0	$0							
533	$0	$0	$0	$0	$0	$0	$0							
534	$0	$0	$0	$0	$0	$0	$0							
535	$0	$0	$0	$0	$0	$0	$0							
536	$0	$0	$0	$0	$0	$0	$0							
537	$0	$0	$0	$0	$0	$0	$0							
538	$0	$0	$0	$0	$0	$0	$0							
539	$0	$0	$0	$0	$0	$0	$0							
540	$0	$0	$0	$0	$0	$0	$0							
541	$0	$0	$0	$0	$0	$0	$0							
542	$0	$0	$0	$0	$0	$0	$0							
543	$0	$0	$0	$0	$0	$0	$0							
544	$0	$0	$0	$0	$0	$0	$0							
545	$0	$0	$0	$0	$0	$0	$0							
546	$0	$0	$0	$0	$0	$0	$0							
547	$0	$0	$0	$0	$0	$0	$0							
548	$0	$0	$0	$0	$0	$0	$0							
549	$0	$0	$0	$0	$0	$0	$0							

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
550	$0	$0	$0	$0	$0	$0	$0							
551	$0	$0	$0	$0	$0	$0	$0							
552	$0	$0	$0	$0	$0	$0	$0							
553	$0	$0	$0	$0	$0	$0	$0							
554	$0	$0	$0	$0	$0	$0	$0							
555	$0	$0	$0	$0	$0	$0	$0							
556	$0	$0	$0	$0	$0	$0	$0							
557	$0	$0	$0	$0	$0	$0	$0							
558	$0	$0	$0	$0	$0	$0	$0							
559	$0	$0	$0	$0	$0	$0	$0							
560	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
561														
562								$0	$0	$0	$0	$0	$0	$0
563								$0	$0	$0	$0	$0	$0	$0
564								$0	$0	$0	$0	$0	$0	$0
565								$0	$0	$0	$0	$0	$0	$0
566								$0	$0	$0	$0	$0	$0	$0
567								$0	$0	$0	$0	$0	$0	$0
568								$0	$0	$0	$0	$0	$0	$0
569								$0	$0	$0	$0	$0	$0	$0
570								$0	$0	$0	$0	$0	$0	$0
571								$0	$0	$0	$0	$0	$0	$0
572								$0	$0	$0	$0	$0	$0	$0
573								$0	$0	$0	$0	$0	$0	$0
574								$0	$0	$0	$0	$0	$0	$0
575								$0	$0	$0	$0	$0	$0	$0
576								$0	$0	$0	$0	$0	$0	$0
577								$0	$0	$0	$0	$0	$0	$0
578								$0	$0	$0	$0	$0	$0	$0
579								$0	$0	$0	$0	$0	$0	$0
580								$0	$0	$0	$0	$0	$0	$0
581								$0	$0	$0	$0	$0	$0	$0
582	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
583														
584	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
585														
586	**Customer Allocation**							**A & G Allocation**						
587	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**	**1**	**2**	**3**	**7**	**8**	**9**	**Sub -total**
588	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Sub -total**
589	64.85%	16.00%	16.72%	1.87%	0.31%	0.25%	100.00%							
590	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
591	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
592	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
593	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
594	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
595	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
596	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
597	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
598	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
599	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
600	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
601	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
602	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
603	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
604	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
605	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
606	34.10%	15.64%	49.33%	0.72%	0.05%	0.15%	100.00%							
607	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
608	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
609	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
610	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
611	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							

	AB	AC	AD	AH	AI	AJ	AV	AW	AX	AY	BC	BD	BE	BQ
612	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%	100.00%							
613	81.54%	3.41%	0.07%	12.37%	1.38%	1.23%	100.00%							
614	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
615	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
616	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%	100.00%							
617	81.54%	3.41%	0.07%	12.37%	1.38%	1.23%	100.00%							
618	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
619	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
620	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%	100.00%							
621	81.54%	3.41%	0.07%	12.37%	1.38%	1.23%	100.00%							
622	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
623	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
624	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%	100.00%							
625	81.54%	3.41%	0.07%	12.37%	1.38%	1.23%	100.00%							
626	76.76%	8.26%	0.88%	11.65%	1.30%	1.15%	100.00%							
627	91.53%	7.65%	0.82%	0.00%	0.00%	0.00%	100.00%							
628	50.64%	22.82%	26.54%	0.00%	0.00%	0.00%	100.00%							
629														
630								53%	17%	26%	3%	0%	0%	100%
631								53%	17%	26%	3%	0%	0%	100%
632								53%	17%	26%	3%	0%	0%	100%
633								53%	17%	26%	3%	0%	0%	100%
634								53%	17%	26%	3%	0%	0%	100%
635								53%	17%	26%	3%	0%	0%	100%
636								53%	17%	26%	3%	0%	0%	100%
637								53%	17%	26%	3%	0%	0%	100%
638								53%	17%	26%	3%	0%	0%	100%
639								53%	17%	26%	3%	0%	0%	100%
640								53%	17%	26%	3%	0%	0%	100%
641								53%	17%	26%	3%	0%	0%	100%
642								53%	17%	26%	3%	0%	0%	100%
643								53%	17%	26%	3%	0%	0%	100%
644								53%	17%	26%	3%	0%	0%	100%
645								53%	17%	26%	3%	0%	0%	100%
646								53%	17%	26%	3%	0%	0%	100%
647								53%	17%	26%	3%	0%	0%	100%
648								53%	17%	26%	3%	0%	0%	100%
649								53%	17%	26%	3%	0%	0%	100%

2010 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet E1 Categorization Worksheet - Second Run

This worksheet details how Density is derived and how Costs are Categorized.

Density of Utility

Density	Number of Customers	kM of Lines
67	11258	169

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.6	*All*
If Density is Between 30 and 60 customers per kM of lines then	MEDIUM	0.4	*All*
If Density is Between > 60 customers per kM of lines then	HIGH	0.35	*Distribution*
If Density is Between > 60 customers per kM of lines then	HIGH	0.3	*Transformers*

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	35%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	35%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	35%
1835	Overhead Conductors and Devices	DNCP	CCA	35%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	35%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	35%
1840	Underground Conduit	DNCP	CCA	35%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	35%
1840-5	Underground Conduit - Secondary	SNCP	CCS	35%
1845	Underground Conductors and Devices	DNCP	CCA	35%

1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	35%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	35%
1850	Line Transformers	LTNCP	CCLT	30%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5010	Load Dispatching	1815-1855 D	1815-1855 C	35%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	35%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	35%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	30%
5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	35%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	35%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	30%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	35%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	35%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	35%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	35%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	35%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	35%
5145	Maintenance of Underground Conduit	1840 D	1840 C	35%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	35%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	30%
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

2006 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet E2 Allocator Worksheet - Second Run

Details:
The worksheet below details how allocators are derived.

			1	2	3	7	8	9
Explanation	**ID and Factors**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Demand Allocators								
1 cp								
Transformation CP	**TCP1**	100.00%	42.14%	14.54%	42.15%	1.01%	0.07%	0.08%
Bulk Delivery (SubTransmission) CP	**BCP1**	100.00%	42.14%	14.54%	42.15%	1.01%	0.07%	0.08%
Distribution CP (Total System)	**DCP1**	100.00%	42.14%	14.54%	42.15%	1.01%	0.07%	0.08%
4 cp								
Transformation CP	**TCP4**	100.00%	39.80%	16.62%	42.65%	0.77%	0.06%	0.10%
Bulk Delivery (SubTransmission) CP	**BCP4**	100.00%	39.80%	16.62%	42.65%	0.77%	0.06%	0.10%
Distribution CP (Total System)	**DCP4**	100.00%	39.80%	16.62%	42.65%	0.77%	0.06%	0.10%
12 cp								
Transformation CP	**TCP12**	100.00%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%
Bulk Delivery (SubTransmission) CP	**BCP12**	100.00%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%
Distribution CP (Total System)	**DCP12**	100.00%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%
NON CO_INCIDENT PEAK								
1 NCP								
Distribution NCP (Total System)	**DNCP1**	100.00%	39.05%	21.48%	39.47%	0.00%	0.00%	0.00%
Primary NCP	**PNCP1**	100.00%	33.90%	22.70%	43.40%	0.00%	0.00%	0.00%
Line Transformer NCP	**LTNCP1**	100.00%	36.09%	24.17%	39.74%	0.00%	0.00%	0.00%
Secondary NCP	**SNCP1**	100.00%	74.03%	19.34%	6.63%	0.00%	0.00%	0.00%
4 NCP								
Distribution NCP (Total System)	**DNCP4**	100.00%	39.21%	20.11%	40.68%	0.00%	0.00%	0.00%
Primary NCP	**PNCP4**	100.00%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%
Line Transformer NCP	**LTNCP4**	100.00%	36.07%	22.67%	41.26%	0.00%	0.00%	0.00%
Secondary NCP	**SNCP4**	100.00%	74.72%	18.32%	6.96%	0.00%	0.00%	0.00%
12 NCP								
Distribution NCP (Total System)	**DNCP12**	100.00%	37.90%	18.83%	43.27%	0.00%	0.00%	0.00%
Primary NCP	**PNCP12**	100.00%	31.74%	19.94%	48.32%	0.00%	0.00%	0.00%
Line Transformer NCP	**LTNCP12**	100.00%	34.04%	21.38%	44.57%	0.00%	0.00%	0.00%
Secondary NCP	**SNCP12**	100.00%	73.99%	18.13%	7.89%	0.00%	0.00%	0.00%
Demand Allocators - Composite								
DEMAND 1815-1855	**1815-1855 D**	100.00%	39.12%	21.42%	39.46%	0.00%	0.00%	0.00%
DEMAND 1808	**1808 D**	100.00%	36.99%	17.77%	44.44%	0.64%	0.05%	0.11%
DEMAND 1815	**1815 D**	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1820	**1820 D**	100.00%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%
DEMAND 1815 & 1820	**1815 & 1820 D**	100.00%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%
DEMAND 1830	**1830 D**	100.00%	54.67%	19.76%	25.58%	0.00%	0.00%	0.00%
DEMAND 1835	**1835 D**	100.00%	41.98%	20.66%	37.36%	0.00%	0.00%	0.00%
DEMAND 1830 & 1835	**1830 & 1835 D**	100.00%	48.67%	20.18%	31.14%	0.00%	0.00%	0.00%
DEMAND 1840	**1840 D**	100.00%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%
DEMAND 1845	**1845 D**	100.00%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%
DEMAND 1840 & 1845	**1840 & 1845 D**	100.00%	33.80%	21.25%	44.96%	0.00%	0.00%	0.00%
DEMAND 1850	**1850 D**	100.00%	36.07%	22.67%	41.26%	0.00%	0.00%	0.00%
DEMAND 1855	**1855 D**	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1860	**1860 D**	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

	A	B	C	D	E	F	J	K	L
69									
70	CUSTOMER ALLOCATORS								
71									
72	Billing Data								
73	kWh	CEN	100.00%	34.10%	15.64%	49.33%	0.72%	0.05%	0.15%
74	kW	CDEM	100.00%	0.00%	0.00%	98.17%	1.71%	0.12%	0.00%
75	kWh - Excl WMP	CEN EWMP	100.00%	34.10%	15.64%	49.33%	0.72%	0.05%	0.15%
76									
77	Dollar Billed (per 2006 EDR)	CREV	100.00%	67.48%	16.60%	15.43%	0.12%	0.03%	0.34%
78	Bad Debt 3 Year Historical Average	BDHA	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
79	Late Payment 3 Year Historical Average	LPHA	100.00%	74.22%	16.20%	9.42%	0.02%	0.02%	0.12%
80									
81	Number of Bills	CNB	100.00%	88.58%	9.53%	1.17%	0.04%	0.41%	0.28%
82	Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	82.60%	9.22%	8.18%
83									
85									
86	Total Number of Customer	CCA	100.00%	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%
87	Subtransmission Customer Base	CCB	100.00%	0.00%	0.00%	0.00%	82.60%	9.22%	8.18%
88	Primary Feeder Customer Base	CCP	100.00%	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%
89	Line Transformer Customer Base	CCLT	100.00%	76.76%	8.26%	0.88%	11.65%	1.30%	1.15%
90	Secondary Feeder Customer Base	CCS	100.00%	81.54%	3.41%	0.07%	12.37%	1.38%	1.23%
91									
92	Weighted - Services	CWCS	100.00%	91.53%	7.65%	0.82%	0.00%	0.00%	0.00%
93	Weighted Meter -Capital	CWMC	100.00%	50.64%	22.82%	26.54%	0.00%	0.00%	0.00%
94	Weighted Meter Reading	CWMR	100.00%	71.49%	17.40%	11.12%	0.00%	0.00%	0.00%
95	Weighted Bills	CWNB	100.00%	75.99%	16.35%	7.04%	0.03%	0.35%	0.24%
96									
97	CUSTOMER ALLOCATORS - Composite								
98									
99	CUSTOMER 1815-1855	1815-1855 C	100.00%	79.69%	7.79%	1.69%	8.95%	1.00%	0.89%
100	CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
101	CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
102	CUSTOMER 1820	1820 C	100.00%	34.10%	15.64%	49.33%	0.72%	0.05%	0.15%
103	CUSTOMER 1815 & 1820	1815 & 1820 C	100.00%	34.10%	15.64%	49.33%	0.72%	0.05%	0.15%
104	CUSTOMER 1830	1830 C	100.00%	79.15%	5.78%	0.53%	12.01%	1.34%	1.19%
105	CUSTOMER 1835	1835 C	100.00%	77.63%	7.28%	0.83%	11.78%	1.31%	1.17%
106	CUSTOMER 1830 & 1835	1830 & 1835 C	100.00%	78.43%	6.49%	0.67%	11.90%	1.33%	1.18%
107	CUSTOMER 1840	1840 C	100.00%	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%
108	CUSTOMER 1845	1845 C	100.00%	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%
109	CUSTOMER 1840 & 1845	1840 & 1845 C	100.00%	76.66%	8.25%	1.02%	11.63%	1.30%	1.15%
110	CUSTOMER 1850	1850 C	100.00%	76.76%	8.26%	0.88%	11.65%	1.30%	1.15%
111	CUSTOMER 1855	1855 C	100.00%	91.53%	7.65%	0.82%	0.00%	0.00%	0.00%
112	CUSTOMER 1860	1860 C	100.00%	50.64%	22.82%	26.54%	0.00%	0.00%	0.00%
113									
114	**Composite Allocators**								
115	Net Fixed Assets	NFA	100.00%	53.08%	16.83%	26.05%	3.34%	0.37%	0.33%
116	Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	53.16%	16.82%	26.03%	3.30%	0.37%	0.33%
117	5005-5340	O&M	100.00%	64.85%	16.00%	16.72%	1.87%	0.31%	0.25%
118									

2010 COST ALLOCATION INFORMATION
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247
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Sheet E3 Demand Allocator Worksheet - Second Run

PLCC WATTS
400

Instructions:
Input sheet for Demand Allocators.

		1	2	3	7	8	9
Customer Classes	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
CCA	13,103	10,045	1,081	133	1,524	170	151
CCB	1,845	0	0	0	1,524	170	151
CCP	13,103	10,045	1,081	133	1,524	170	151
CCLT	13,085	10,045	1,081	115	1,524	170	151
CCS	12,319	10,045	420	9	1,524	170	151
PLCC-CCA	5,241	4,018	432	53	610	68	60
PLCC-CCB	738	0	0	0	610	68	60
PLCC-CCP	5,241	4,018	432	53	610	68	60
PLCC-CCLT	5,234	4,018	432	46	610	68	60
PLCC-CCS	4,927	4,018	168	4	610	68	60
1NCP							
DNCP1	48,889	18,896	10,396	19,100	419	30	48
PNCP1	48,889	18,896	10,396	19,100	419	30	48
LTNCP1	46,215	18,896	10,396	16,426	419	30	48
SNCP1	24,785	18,896	4,054	1,337	419	30	48
PLCC - 1NCP							
DNCP1A	48,392	18,896	10,396	19,100	0	0	0
PNCP1A	43,889	14,878	9,964	19,047	0	0	0
LTNCP1A	41,222	14,878	9,964	16,380	0	0	0
SNCP1A	20,098	14,878	3,886	1,333	0	0	0
4 NCP							
DNCP4	186,426	72,316	37,090	75,035	1,678	121	186
PNCP4	186,426	72,316	37,090	75,035	1,678	121	186
LTNCP4	175,921	72,316	37,090	64,530	1,678	121	186
SNCP4	94,018	72,316	14,465	5,252	1,678	121	186
PLCC - 4NCP							
DNCP4A	184,441	72,316	37,090	75,035	0	0	0
PNCP4A	166,429	56,245	35,361	74,822	0	0	0
LTNCP4A	155,953	56,245	35,361	64,346	0	0	0
SNCP4A	75,276	56,245	13,793	5,238	0	0	0
12NCP							
DNCP12	510,523	191,223	95,022	218,367	5,033	363	515
PNCP12	510,523	191,223	95,022	218,367	5,033	363	515
LTNCP12	479,951	191,223	95,022	187,795	5,033	363	515
SNCP12	249,479	191,223	37,058	15,286	5,033	363	515
PLCC - 12NCP							
DNCP12A	504,612	191,223	95,022	218,367	0	0	0
PNCP12A	450,573	143,010	89,835	217,728	0	0	0
LTNCP12A	420,088	143,010	89,835	187,243	0	0	0
SNCP12A	193,295	143,010	35,042	15,242	0	0	0

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2010 COST ALLOCATION INFORMATION FILING

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet E4 Trial Balance Allocation Detail Worksheet - Second Run

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. Finally, it will show how costs are being grouped together for presentation purposes.

Details:

The worksheet below details how costs are treated, categorized, and grouped.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP											
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS						
1860	Meters	Services and Meters	dp			CWMC			CWMC						
1905	Land	Land and Buildings	gp							NFA ECC					
1906	Land Rights	Land and Buildings	gp							NFA ECC					
1908	Buildings and Fixtures	General Plant	gp							NFA ECC					
1910	Leasehold Improvements	General Plant	gp							NFA ECC					
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC					
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC					
1925	Computer Software	IT Assets	gp							NFA ECC					
1930	Transportation Equipment	Equipment	gp							NFA ECC					
1935	Stores Equipment	Equipment	gp							NFA ECC					
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC					
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC					
1950	Power Operated Equipment	Equipment	gp							NFA ECC					
1955	Communication Equipment	Equipment	gp							NFA ECC					
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC					

Details:

The worksheet below details how costs are treated, categorized, and grouped.

Uniform System of Accounts Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC						
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC						
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC						
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC						
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout							
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC						
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC						
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout							
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout							
3046	Balance Transferred From Income	Equity	NI								NFA					
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV					
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB					
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB					
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB					
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA					
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA					
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA					
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA					
4225	Late Payment Charges	Late Payment Charges	mi								LPHA					
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB					
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA					
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA					
4305	Regulatory Debits	Other Income & Deductions	mi								NFA					
4310	Regulatory Credits	Other Income & Deductions	mi								NFA					
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA					
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA					
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA					
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA					
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA					
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA					
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA					
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA					
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA					
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA					
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA					
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA					
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA					
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA					
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA					
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA					
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA					
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN						
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP						
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN						
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D

Details:

The worksheet below details how costs are treated, categorized, and grouped.

Uniform System of Accounts Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835	x	830 & 1835	1830 & 1835 C					1830 & 1835	1830 & 1835 D
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835	x	830 & 1835	1830 & 1835 C					1830 & 1835	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835		830 & 1835	1830 & 1835 C					1830 & 1835	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845	x	840 & 1845	1840 & 1845 C					1840 & 1845	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845	x	840 & 1845	1840 & 1845 C					1840 & 1845	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845		840 & 1845	1840 & 1845 C					1840 & 1845	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC						
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA						
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA						
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855	1815-1855 C	x	1815-1855	1815-1855 C					1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845	x	840 & 1845	1840 & 1845 C					1840 & 1845	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835	x	830 & 1835	1830 & 1835 C					1830 & 1835	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M					
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855	1815-1855 C	x	1815-1855	1815-1855 C					1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C					1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C					1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835	x	830 & 1835	1830 & 1835 C					1830 & 1835	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C					1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C					1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C					1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						

Details:

The worksheet below details how costs are treated, categorized, and grouped.

Uniform System of Accounts Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M					
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M					
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC					
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M					
5505	Supervision	Other Distribution Expenses	ad							O&M					
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M					
5515	Advertising Expense	Advertising Expenses	ad							O&M					
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M					
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M					
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M					
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC					
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M					
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M					
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M					
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5660	General Advertising Expenses	Advertising Expenses	ad							O&M					
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA					
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

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2010 COST ALLOCATION INFORMATION FILING
Orangeville Hydro Limited
EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet E5 Reconciliation Worksheet - Second Run

Details:

The worksheet below shows reconciliation of costs included and excluded in the Trial Balance.

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
1565	~~Conservation and Demand Management~~ Expenditures and Recoveries	$0		$0		$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0		$0		$0	$0	$0	$0	$0	$0
1805	Land		$0	$0		$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$29,126	$29,126		$0	$29,126	$29,126	$0	$29,126	$0
1806	Land Rights		$0	$0		$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$33,817	$33,817		$0	$33,817	$33,817	$0	$33,817	$0
1808	Buildings and Fixtures		$0	$0		$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$15,296	$15,296		$0	$15,296	$15,296	$0	$15,296	$0
1810	Leasehold Improvements		$0	$0		$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$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
1820	Distribution Station Equipment - Normally Primary below 50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		$0	$0		$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		$783,580	$783,580		$0	$783,580	$783,580	$0	$783,580	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		$188,483	$188,483		$0	$188,483	$188,483	$0	$188,483	$0
1825	Storage Battery Equipment		$0	$0		$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0		$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures		$0	$0		$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$0	$0		$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		$2,104,803	$2,104,803		$0	$2,104,803	$2,104,803	$0	$2,104,803	$0
1830-5	Poles, Towers and Fixtures - Secondary		$2,190,713	$2,190,713		$0	$2,190,713	$2,190,713	$0	$2,190,713	$0
1835	Overhead Conductors and Devices		$0	$0		$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$0	$0		$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		$3,077,146	$3,077,146		$0	$3,077,146	$3,077,146	$0	$3,077,146	$0
1835-5	Overhead Conductors and Devices - Secondary		$769,286	$769,286		$0	$769,286	$769,286	$0	$769,286	$0
1840	Underground Conduit		$0	$0		$0	$0	$0	$0	$0	$0

1840-3	Underground Conduit - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		$3,819,364	$3,819,364	$0	$3,819,364	$3,819,364	$0	$3,819,364	$0
1840-5	Underground Conduit - Secondary		$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices		$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		$4,220,334	$4,220,334	$0	$4,220,334	$4,220,334	$0	$4,220,334	$0
1845-5	Underground Conductors and Devices - Secondary		$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers		$8,711,874	$8,711,874	$0	$8,711,874	$8,711,874	$0	$8,711,874	$0
1855	Services		$2,394,181	$2,394,181	$0	$2,394,181	$2,394,181	$0	$2,394,181	$0
1860	Meters		$1,865,032	$1,865,032	$0	$1,865,032	$1,865,032	$0	$1,865,032	$0
1905	Land	$0	$144,400	$144,400	$0	$144,400	$144,400	$0	$144,400	$0
1906	Land Rights	$0	$4,938	$4,938	$0	$4,938	$4,938	$0	$4,938	$0
1908	Buildings and Fixtures	$0	$2,733,924	$2,733,924	$0	$2,733,924	$2,733,924	$0	$2,733,924	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	$197,922	$197,922	$0	$197,922	$197,922	$0	$197,922	$0
1920	Computer Equipment - Hardware	$0	$244,809	$244,809	$0	$244,809	$244,809	$0	$244,809	$0
1925	Computer Software	$0	$709,106	$709,106	$0	$709,106	$709,106	$0	$709,106	$0
1930	Transportation Equipment	$0	$1,119,965	$1,119,965	$0	$1,119,965	$1,119,965	$0	$1,119,965	$0
1935	Stores Equipment	$0	$34,825	$34,825	$0	$34,825	$34,825	$0	$34,825	$0
1940	Tools, Shop and Garage Equipment	$0	$153,358	$153,358	$0	$153,358	$153,358	$0	$153,358	$0
1945	Measurement and Testing Equipment	$0	$16,819	$16,819	$0	$16,819	$16,819	$0	$16,819	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0	$19,323	$19,323	$0	$19,323	$19,323	$0	$19,323	$0
1960	Miscellaneous Equipment	$0	$35,302	$35,302	$0	$35,302	$35,302	$0	$35,302	$0
1970	Load Management Controls - Customer Premises	$0	$11,000	$11,000	$0	$11,000	$11,000	$0	$11,000	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$7,500	$7,500	$0	$7,500	$7,500	$0	$7,500	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	($3,688,894)	$0	($3,688,894)	$0	($3,688,894)	($3,688,894)	$0	($3,688,894)	($0)
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($17,513,537)		($17,513,537)	$0	($17,513,537)	($17,513,537)	$0	($17,513,573)	$36
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0		$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	($570,284)		($570,284)	$0	($570,284)	($570,284)	$0	($570,284)	$0
4080	Distribution Services Revenue	($5,005,962)		($5,005,962)	$0	($5,005,962)	($5,005,962)	$0	($5,005,962)	$0
4082	Retail Services Revenues	($19,546)		($19,546)	$0	($19,546)	($19,546)	$0	($19,546)	$0
4084	Service Transaction Requests (STR) Revenues	($443)		($443)	$0	($443)	($443)	$0	($443)	$0
4090	Electric Services Incidental to Energy Sales	($26,087)		($26,087)	$0	($26,087)	($26,087)	$0	($26,087)	$0
4205	Interdepartmental Rents	$0		$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	($54,516)		($54,516)	$0	($54,516)	($54,516)	$0	($54,516)	$0
4215	Other Utility Operating Income	($15,272)		($15,272)	$0	($15,272)	($15,272)	$0	($15,272)	$0
4220	Other Electric Revenues	$0		$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($37,522)		($37,522)	$0	($37,522)	($37,522)	$0	($37,522)	$0
4235	Miscellaneous Service Revenues	($159,163)		($159,163)	$0	($159,163)	($159,163)	$0	($159,163)	$0
4240	Provision for Rate Refunds	$0		$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0		$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0		$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	$0		$0	$0	$0	$0	$0	$0	$0

4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	($800)	($800)	$0	($800)	($800)	$0	($800)	$0
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	($500)	($500)	$0	($500)	($500)	$0	($500)	$0
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	($42,423)	($42,423)	$0	($42,423)	($42,423)	$0	($42,423)	$0
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$15,828,613	$15,828,613	$0	$15,828,613	$15,828,613	$0	$15,828,613	$0
4708	Charges-WMS	$1,694,433	$1,694,433	$0	$1,694,433	$1,694,433	$0	$1,694,433	$0
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$205,513	$205,513	$0	$205,513	$205,513	$0	$205,513	$0
4714	Charges-NW	$1,235,637	$1,235,637	$0	$1,235,637	$1,235,637	$0	$1,235,637	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$702,316	$702,316	$0	$702,316	$702,316	$0	$702,316	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$1,013	$1,013	$0	$1,013	$1,013	$0	$1,013	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$66,355	$66,355	$0	$66,355	$66,355	$0	$66,355	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$3,758	$3,758	$0	$3,758	$3,758	$0	$3,758	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$1,080	$1,080	$0	$1,080	$1,080	$0	$1,080	$0
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$3,558	$3,558	$0	$3,558	$3,558	$0	$3,558	$0

5040	Underground Distribution Lines and Feeders - Operation Labour	$1,492	$1,492	$0	$1,492	$1,492	$0	$1,492	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$270	$270	$0	$270	$270	$0	$270	$0
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$694	$694	$0	$694	$694	$0	$694	$0
5065	Meter Expense	$103,931	$103,931	$0	$103,931	$103,931	$0	$103,931	$0
5070	Customer Premises - Operation Labour	$44,701	$44,701	$0	$44,701	$44,701	$0	$44,701	$0
5075	Customer Premises - Materials and Expenses	$19,505	$19,505	$0	$19,505	$19,505	$0	$19,505	$0
5085	Miscellaneous Distribution Expense	$156,263	$156,263	$0	$156,263	$156,263	$0	$156,263	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$6,325	$6,325	$0	$6,325	$6,325	$0	$6,325	$0
5105	Maintenance Supervision and Engineering	$128,570	$128,570	$0	$128,570	$128,570	$0	$128,570	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$11,345	$11,345	$0	$11,345	$11,345	$0	$11,345	$0
5120	Maintenance of Poles, Towers and Fixtures	$23,374	$23,374	$0	$23,374	$23,374	$0	$23,374	$0
5125	Maintenance of Overhead Conductors and Devices	$69,136	$69,136	$0	$69,136	$69,136	$0	$69,136	$0
5130	Maintenance of Overhead Services	$19,169	$19,169	$0	$19,169	$19,169	$0	$19,169	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$104,245	$104,245	$0	$104,245	$104,245	$0	$104,245	$0
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$10,732	$10,732	$0	$10,732	$10,732	$0	$10,732	$0
5155	Maintenance of Underground Services	$80,437	$80,437	$0	$80,437	$80,437	$0	$80,437	$0
5160	Maintenance of Line Transformers	$45,413	$45,413	$0	$45,413	$45,413	$0	$45,413	$0
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$26,093	$26,093	$0	$26,093	$26,093	$0	$26,093	$0
5310	Meter Reading Expense	$114,976	$114,976	$0	$114,976	$114,976	$0	$114,976	$0
5315	Customer Billing	$238,412	$238,412	$0	$238,412	$238,412	$0	$238,412	$0
5320	Collecting	$160,472	$160,472	$0	$160,472	$160,472	$0	$160,472	$0
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$20,000	$20,000	$0	$20,000	$20,000	$0	$20,000	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$28,862	$28,862	$0	$28,862	$28,862	$0	$28,862	$0
5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$0	$0
5420	Community Safety Program	$0	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$386,005	$386,005	$0	$386,005	$386,005	$0	$386,005	$0

5610	Management Salaries and Expenses	$132,149		$132,149		$0	$132,149	$132,149	$0	$132,149	$0
5615	General Administrative Salaries and Expenses	$270,196		$270,196		$0	$270,196	$270,196	$0	$270,196	$0
5620	Office Supplies and Expenses	$53,799		$53,799		$0	$53,799	$53,799	$0	$53,799	$0
5625	Administrative Expense Transferred Credit	$0		$0		$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$123,329		$123,329		$0	$123,329	$123,329	$0	$123,329	$0
5635	Property Insurance	$26,412		$26,412		$0	$26,412	$26,412	$0	$26,412	$0
5640	Injuries and Damages	$20,253		$20,253		$0	$20,253	$20,253	$0	$20,253	$0
5645	Employee Pensions and Benefits	$37,330		$37,330		$0	$37,330	$37,330	$0	$37,330	$0
5650	Franchise Requirements	$0		$0		$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$77,072		$77,072		$0	$77,072	$77,072	$0	$77,072	$0
5660	General Advertising Expenses	$0		$0		$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	$74,656		$74,656		$0	$74,656	$74,656	$0	$74,656	$0
5670	Rent	$0		$0		$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$77,632		$77,632		$0	$77,632	$77,632	$0	$77,632	$0
5680	Electrical Safety Authority Fees	$0		$0		$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0		$0		$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$1,119,762		$1,119,762		$0	$1,119,762	$1,119,762	$0	$1,119,762	$0
5710	Amortization of Limited Term Electric Plant	$0		$0		$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$0		$0		$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0		$0		$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0		$0		$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	$0		$0		$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	$0		$0		$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	$652,936		$652,936		$0	$652,936	$652,936	$0	$652,936	$0
6105	Taxes Other Than Income Taxes	$0		$0		$0	$0	$0	$0	$0	$0
6110	Income Taxes	$250,237		$250,237		$0	$250,237	$250,237	$0	$250,237	$0
6205	Donations	$0		$0		$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0		$0		$0	$0	$0	$0	$0	$0
6215	Penalties	$0		$0		$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0		$0		$0	$0	$0	$0	$0	$0
	Total	**($2,676,486)**	**$35,636,225**	**$32,959,738**	**Control**	**$0** **$32,959,738**	**$32,959,738**	**$32,959,738**	**$0**	**$32,959,703**	**$36**

[redacted]

Grouping by Allocator	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 78,713	$ -	$ -	$ 78,713	$ 78,713	$ -	$ 78,713	$ -
1830	$ 23,374	$ -	$ -	$ 23,374	$ 23,374	$ -	$ 23,374	$ -
1835	$ 69,136	$ -	$ -	$ 69,136	$ 69,136	$ -	$ 69,136	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 10,732	$ -	$ -	$ 10,732	$ 10,732	$ -	$ 10,732	$ -
1850	$ 49,665	$ -	$ -	$ 49,665	$ 49,665	$ -	$ 49,665	$ -
1855	$ 99,606	$ -	$ -	$ 99,606	$ 99,606	$ -	$ 99,606	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 284,833	$ -	$ -	$ 284,833	$ 284,833	$ -	$ 284,833	$ -
1830 & 1835	$ 109,083	$ -	$ -	$ 109,083	$ 109,083	$ -	$ 109,083	$ -
1840 & 1845	$ 1,762	$ -	$ -	$ 1,762	$ 1,762	$ -	$ 1,762	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 20,000	$ -	$ -	$ 20,000	$ 20,000	$ -	$ 20,000	$ -
Break Out	$ (20,082,669)	$ -	$ -	$ (20,082,669)	$ (20,082,669)	$ -	$ (20,082,705)	$ 36
CCA	$ 64,207	$ -	$ -	$ 64,207	$ 64,207	$ -	$ 64,207	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 2,126,436	$ -	$ -	$ 2,126,436	$ 2,126,436	$ -	$ 2,126,436	$ -
CEN EWMP	$ 17,728,559	$ -	$ -	$ 17,728,559	$ 17,728,559	$ -	$ 17,728,559	$ -
CREV	$ (5,005,962)	$ -	$ -	$ (5,005,962)	$ (5,005,962)	$ -	$ (5,005,962)	$ -
CWCS	$ 2,394,181	$ -	$ -	$ 2,394,181	$ 2,394,181	$ -	$ 2,394,181	$ -
CWMC	$ 1,968,963	$ -	$ -	$ 1,968,963	$ 1,968,963	$ -	$ 1,968,963	$ -
CWMR	$ 114,976	$ -	$ -	$ 114,976	$ 114,976	$ -	$ 114,976	$ -
CWNB	$ 219,738	$ -	$ -	$ 219,738	$ 219,738	$ -	$ 219,738	$ -
DCP	$ 78,239	$ -	$ -	$ 78,239	$ 78,239	$ -	$ 78,239	$ -
LPHA	$ (37,522)	$ -	$ -	$ (37,522)	$ (37,522)	$ -	$ (37,522)	$ -
LTNCP	$ 8,711,874	$ -	$ -	$ 8,711,874	$ 8,711,874	$ -	$ 8,711,874	$ -
NFA	$ 219,378	$ -	$ -	$ 219,378	$ 219,378	$ -	$ 219,378	$ -
NFA ECC	$ 5,459,602	$ -	$ -	$ 5,459,602	$ 5,459,602	$ -	$ 5,459,602	$ -
O&M	$ 1,287,607	$ -	$ -	$ 1,287,607	$ 1,287,607	$ -	$ 1,287,607	$ -
PNCP	$ 14,005,227	$ -	$ -	$ 14,005,227	$ 14,005,227	$ -	$ 14,005,227	$ -
SNCP	$ 2,960,000	$ -	$ -	$ 2,960,000	$ 2,960,000	$ -	$ 2,960,000	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 32,959,738**	**$ -**	**$ -**	**$ 32,959,738**	**$ 32,959,738**	**$ -**	**$ 32,959,703**	**$ 36**

2006 COST ALLOCATION

Orangeville Hydro Limited

EB-2002-0400 EB-2006-0247

Friday, August 28, 2009

Sheet E5 Reconciliation Worksheet - Second R

If you have completed the Cost Allocation filing model and prepare
your findings to the Ontario Energy Board, please note that you ha
options.

OPTION #1 - Detailed

Step 1: Save this file as "LDCname_Detailed_CA_model_RUN#.xls"
Step 2: Printout sheets I2, I4, and O1

OPTION #2 - Rolled Up

Step 1: Save this file as "LDCname_Detailed_CA_model_RUN#.xls"
Step 2: **Click on the Option 2 Button**
Step 3: **Save this file as "LDCname_RolledUp_CA_model_RUN#.xls"**
Step 4: Printout sheets I2, I4, and O1

OPTION 2

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RATE DESIGN OVERVIEW:

OHL is proposing in this application to harmonize the distribution rates for the Orangeville service area and the Grand Valley service area. This Exhibit documents the calculation of OHL's proposed distribution rates by rate class for the 2010 test year, based on rate design as proposed in this Exhibit.

OHL has determined its total 2010 service revenue requirement to be $5,362,234 . The total revenue offsets in the amount of $356,272 reduce OHL's total service revenue requirement to a base revenue requirement to $5,005,962 which is used to determine the proposed distribution rates. The base revenue requirement is derived from OHL's 2010 capital and operating forecasts, weather normalized usage, forecasted customer counts, and OHL's regulated return on rate base. The revenue requirements are summarized below in Table 1:

Table 1

Calculation of Base Revenue Requirement

OM&A Expenses	2,769,015
Amortization Expenses	1,119,762
Total Distribution Expenses	3,890,877
Regulated Return On Capital	1,223,219.60
PILs (with gross-up)	248,138
Service Revenue Requirement	5,362,234
Less: Revenue Offsets	-356,272
Base Revenue Requirement	**5,005,962**

The outstanding base revenue requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 7 – Cost Allocation.

Table 2

Proposed Apportionment of Revenue to Rate Classes

Rate Classification	Proposed Proportion of Revenue
Residential	64.72%
General Service Less Than 50 kW	16.67%
General Service Greater Than 50 kW	17.20%
Street Lights	0.98%
Sentinel Lights	0.13%
Unmetered Scattered Load	0.30%
Total	100.00%

The following Table 3 outlines the results of this allocation.

Table 3

Allocation of Outstanding Base Revenue Requirement

Rate Classification	Proposed Revenue
Residential	$3,239,709
General Service Less Than 50 kW	$834,494
General Service Greater Than 50 kW	$861,026
Street Lights	$49,159
Sentinel Lights	$6,558
Unmetered Scattered Load	$15,018
Total	**$5,005,962**

Determination of Monthly Fixed/Volumetric Charges:

OHL’s current OEB-approved (2009 IRM) volumetric and monthly fixed charges are summarized in Table 4 and Table 5 as follows.

Table 4(a)

Orangeville Service Area Current Monthly Fixed Charges (Excludes Smart Meter)

Rate Class	**Current Monthly Fixed Charge**	**Customer\ Connection**
Residential	$16.07	Customer
General Service Less Than 50 kW	$29.78	Customer
General Service Greater Than 50 kW	$183.39	Customer
General Service Greater Than 50 kW-TOU	$2,141.44	Customer
Street Lights	$0.04	Connection
Sentinel Lights	$0.40	Connection
Unmetered Scattered Load	$29.78	Customer

Table 4(b)

Grand Valley Service Area Current Monthly Fixed Charges (Excludes Smart Meter)

Rate Class	**Current Monthly Fixed Charge**	**Customer\ Connection**
Residential	$13.30	Customer
General Service Less Than 50 kW	$21.36	Customer
General Service Greater Than 50 kW	$232.99	Customer
Street Lights	$0.93	Connection
Unmetered Scattered Load	$21.36	Customer

Table 5(a)

Orangeville Service Area Current Monthly Volumetric Charges

Rate Class	Current Monthly Volumetric Charge	Unit
Residential	0.0135	kWh
General Service Less Than 50 kW	0.0101	kWh
General Service Greater Than 50 kW	1.8266	kW
General Service Greater Than 50 kW-TOU	1.7580	kW
Street Lights	0.6418	kW
Sentinel Lights	1.9320	kW
Unmetered Scattered Load	0.0101	kWh

Table 5(b)

Grand Valley Service Area Current Monthly Volumetric Charges

Rate Class	Current Monthly Volumetric Charge	Unit
Residential	0.0163	kWh
General Service Less Than 50 kW	0.0141	kWh
General Service Greater Than 50 kW	3.9508	kW
Street Lights	5.8417	kW
Unmetered Scattered Load	0.0141	kWh

In order to harmonize the rates, OHL used the existing approved fixed charges applied to the forecasted number of customers for the Orangeville Service area for 2010 and the forecasted number of customers for the Grand Valley Service area for 2010. The approved volumetric charge for Orangeville service area was applied to the forecasted volumetric billing determinants and the approved volumetric charge for Grand Valley service area was applied to the forecasted volumetric billing determinants in that area and combined. The following Table 6 outlines the resulting current split between fixed and variable distribution revenue.

OHL has also eliminated the >50 kW to 4999 kW –Time of Use Class in coordination with Run 2 of the Cost Allocation Model. In Exhibit 7 Run 2 of the Cost Allocation model also eliminates this class.

Table 6

Fixed and Variable Proportion

Rate Class	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	64.95%	35.05%
General Service Less Than 50 kW	52.08%	47.92%
General Service Greater Than 50 kW	48.00%	52.00%
Street Lights	53.76%	46.24%
Sentinel Lights	59.31%	40.69%
Unmetered Scattered Load	77.25%	22.75%

OHL submits that it is appropriate for 2010 to maintain the same fixed/variable proportions assumed in the current rates for all customer classifications with the exception of General Service 50 to 4999 kW.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, referred to in Exhibit 7 above, the OEB addressed a number of “Other Rate Matters”, including the treatment of the fixed rate component (the Monthly Service Charge, or “MSC”) of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled “Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors”. OHL’s MSCs exceeds that floor amount. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB’s Rate Review proceeding (EB-2009-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time.

Until the OEB's Rate Review proceeding (EB-2009-0031) is completed and consistent with Norfolk Power Distribution Inc. 2009 Rate Decision (EB-2007-0753), OHL submits that an MSC ceiling has not been established and that it is appropriate for the purposes of setting rates in this Application to maintain the current fixed and variable proportions of its rates with the exception of General Service 50 to 4999 kW. OHL is recommending that the fixed portion of this customer classification be reduced from the current 56.55% to 51.16%. Customers at the low end of this rate classification (50kW to 100kW) would be subject to higher bill impact percentages at the current fixed rate proportion. Consideration should be given to reducing the large kW range within this classification by introducing a new customer class at some point in the future. All other changes in MSCs are due solely to changes in the total base revenue requirement attributable to each customer class. The following Table 7 provides OHL's calculations of its proposed monthly fixed distribution charges for the 2010 Test Year assuming the fixed/variable split supporting the current approved rates.

Table 7

Proposed Fixed Distribution Charge

Rate Class	Total Base Revenue Requirement	Fixed Revenue Proportion	2010 Test Year Customers	Proposed Fixed Distribution Charge
Residential	3,239,709	64.95%	10,045	17.46
General Service Less Than 50 kW	834,494	52.08%	1,081	33.52
General Service Greater Than 50 kW	861,026	48.00%	133	264.94
Street Lights	49,159	53.76%	2,724	0.81
Sentinel Lights	6,558	59.31%	170	1.91
Unmetered Scattered Load	15,018	77.25%	151	6.40
Total	5,005,962			

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2010 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8 provides OHL's calculations of its proposed variable distribution charges for the 2010 Test Year assuming the same fixed/variable split used in designing the current approved rates with the exception of the GS 50 to 4,999 kW class.

Table 8

Variable Distribution Charge Calculation

Rate Class	Total Base Revenue Requirement	Variable Revenue Proportion	2010 Test Volumetric Billing Determinant	Unit	Proposed Volumetric Distribution Charge
Residential	3,239,709	35.05%	84,928,233	kWh	0.0134
General Service Less Than 50 kW	834,494	47.92%	38,954,924	kWh	0.0103
General Service Greater Than 50 kW	861,026	52.00%	293,178	kW	1.8345
Street Lights	49,159	46.24%	5,102	kW	4.4557
Sentinel Lights	6,558	40.69%	360	kW	7.4165
Unmetered Scattered Load	15,018	22.75%	376,928	kWh	0.009
Total	5,005,962				

Adjustment to Transformer Allowance:

Currently, OHL provides a Transformer Allowance to those customers that own their transformation facilities. OHL proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. The transformer allowance amount of $90,131 was determined by the projected forecast for those customers who own their transformers. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

Low Voltage Charges:

OHL is an embedded distributor with Hydro One and is subject to Low Voltage charges. OHL has revised the charges based on Hydro One recent 2009 Decision EB-2008-0187. OHL has forecasted the total Low Voltage charges to be approximately $200,513 based on this decision.

OHL allocated the low voltage costs by customer class based on the allocation of the retail transmission connection rates to develop percentage of allocation for the total amount of $200,513 to the classes.

Low Voltage Costs Allocated by Customer Class

Customer Class	Retail Transmission Connection Rate ($)		Basis for Allocation ($)	Allocation Percentages	Allocated $
	per KWh	per kW			
Residential	0.0030		257,485	37.58%	75,346
GS < 50 kW	0.0027		106,674	15.57%	31,215
GS >50 kW		1.0761	315,487	46.04%	92,318
GS >50 kW - TOU-eliminate			0	0.00%	0
Sentinel Lights		0.8493	306	0.04%	89
Street Lighting		0.8318	4,244	0.62%	1,242
USL	0.0027		1,032	0.15%	302
TOTALS			**685,228**	**100.00%**	**200,513**

OHL then designed the rates based on the allocation percentages and revenue projection by each class as set out in the table below.

RATES - Low Voltage Adjustment

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	75,346	84,928,233	0	kWh	0.0009	
GS < 50 kW	31,215	38,954,924	0	kWh	0.0008	
GS >50 kW	92,318	122,840,423	293,178	kW		0.3149
GS >50 kW - TOU-eliminate	0	0	0	kW		
Sentinel Lights	89	129,899	360	kW		0.2485
Street Lighting	1,242	1,798,732	5,102	kW		0.2434
USL	302	376,928	0	kWh	0.0008	
TOTALS	**200,513**	**249,029,139**	**298,639**			

Proposed Distribution Rates:

The following Table 9 sets out OHL's proposed 2010 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance, Low Voltage recovery, regulatory assets rate rider and the smart meter rate adder of $1.00/month:

Table 9

Proposed 2010 Electricity Distribution Rates

Customer Class	Item Description	Unit	Rate ($)
Residential			
	Monthly Service Charge	per month	17.46
	Distribution Volumetric Rate	per kWh	0.0134
	LV Charges	per kWh	0.0009
	Smart Meter Rate Rider	per month	1.0000
	Regulatory Assets Rate Rider	per kWh	(0.0013)
GS < 50 kW			
	Monthly Service Charge	per month	33.52
	Distribution Volumetric Rate	per kWh	0.0103
	LV Charges	per kWh	0.0008
	Smart Meter Rate Rider	per month	1.0000
	Regulatory Assets Rate Rider	per kWh	(0.0013)
GS >50 kW			
	Monthly Service Charge	per month	264.94
	Distribution Volumetric Rate	per kW	1.8345
	LV Charges	per kW	0.3149
	Smart Meter Rate Rider	per month	1.0000
	Regulatory Assets Rate Rider	per kW	(0.5080)
Sentinel Lights			
	Monthly Service Charge	per connection	1.91
	Distribution Volumetric Rate	per kW	7.4165
	LV Charges	per kW	0.2485
	Regulatory Assets Rate Rider	per kW	(0.4868)
Street Lighting			
	Monthly Service Charge	per connection	0.81
	Distribution Volumetric Rate	per kW	4.4557
	LV Charges	per kW	0.2434
	Regulatory Assets Rate Rider	per kW	(0.4520)
USL			
	Monthly Service Charge	per connection	6.40
	Distribution Volumetric Rate	per kWh	0.0091
	LV Charges	per kWh	0.0008
	Regulatory Assets Rate Rider	per kWh	(0.0010)

OHL has eliminated the legacy General Service Greater than 50 kW TOU rate class. OHL has also changed the monthly service charge for the unmetered scattered load class from “per Customer” to “per Connection”.

RATE MITIGATION:

OHL submits that the bill impacts of its proposed 2010 electricity distribution rates are not so significant as to warrant any mitigation measures.

OTHER ELECTRICITY CHARGES:

OHL proposes to leave rates for Wholesale Market Service, Rural Rate Protection Charge, and Standard Supply Service – Administrative Charge at rates approved by the OEB in EB-2008-0177 and EB-2008-0204 (2009 rates). Both the Network Service and Line and Transformation Connection rates were revised in the 2009 IRM rate setting process to reflect the increase in the Uniform Transmission Rates EB-2008-0113 and according to the Guidelines G-2008-0001 issued October 22, 2008.

OHL is proposing to harmonize the retail transmission rates for Orangeville and Grand Valley. This will be completed by using the proposed rates for 2010. As indicated in the chart below the current rates for each service area are in reverse of each other. Utilizing Orangeville service area transmission rates are also more aligned with the variances for both network and connection.

	Existing Rates for Grand Valley	Existing Rates for Orangeville	Proposed Harmonized 2010 Rates
Transmission Network			
Residential	0.0033	0.0052	0.0052
< 50 kW GS	0.0031	0.0048	0.0048
>50 kW GS	1.1714	1.9365	1.9365
Street Lighting	1.1714	1.4605	1.4605
Sentinel Lighting	n/a	1.4678	1.4678
Unmetered Scattered Load	0.0031	0.0048	0.0048
Transmission Connection			
Residential	0.0051	0.0031	0.0030
< 50 kW GS	0.0045	0.0028	0.0027
>50 kW GS	1.7871	1.1003	1.0761
Street Lighting	1.7871	0.8505	0.8318
Sentinel Lighting	n/a	0.8684	0.8493
Unmetered Scattered Load	0.0045	0.0028	0.0027

OHL has followed the guidelines for Electricity Distribution Retail Transmission Service Rates G-2008-0001 Revision 1.0 issued July 22, 2009 and has adjusted the Retail Transmission Line and Transformation Connection Service per the Decision and Rate Order EB-2008-072 with a decrease of 2.2%. EB-2008-072 also called for an increase in the Network Service Rate of 3.5%

however OHL's variance accounts indicated that we should not increase the existing rate by 5%. OHL proposes to maintain the existing Transmission Network rate charged to customers. There has been an over-collection of the transmission network service rate. The Retail Transmission Network variance in 2008 increased for an additional credit of $51,698.

Table 10

Retail Transmission Service Rates (RTSR)

Month	2007			2008			2007			2008		
	Retail Transmission Network Cost	Retail Transmission Network Billing	Variance	Retail Transmission Network Cost	Retail Transmission Network Billing	Variance	Retail Transmission Connection Cost	Retail Transmission Connection Billing	Variance	Retail Transmission Connection Cost	Retail Transmission Connection Billing	Variance
January	112,243	96,401	15,843	108,902	88,604	20,298	60,151	50,477	9,673	58,340	46,161	12,180
February	112,667	120,990	(8,323)	106,959	109,865	(2,906)	60,481	68,615	(8,134)	57,309	82,034	(24,725)
March	103,466	132,120	(28,654)	97,695	163,262	(65,566)	56,327	73,782	(17,454)	52,485	66,798	(14,313)
April	96,690	113,868	(17,179)	86,229	94,779	(8,550)	51,914	66,550	(14,636)	48,867	60,986	(12,119)
May	106,055	106,022	32	82,235	59,588	22,647	57,260	60,324	(3,064)	56,460	37,094	19,366
June	119,650	108,945	10,704	85,196	132,403	(47,207)	64,098	59,595	4,503	58,562	86,792	(28,231)
July	117,480	125,007	(7,527)	88,677	70,281	18,396	62,936	70,572	(7,636)	60,904	43,694	17,209
August	117,190	102,315	14,875	84,322	72,084	12,237	62,780	61,555	1,225	57,892	45,860	12,033
September	110,762	112,984	(2,222)	71,403	105,940	(34,537)	59,369	63,505	(4,136)	49,339	68,097	(18,758)
October	98,346	120,417	(22,072)	76,485	77,640	(1,156)	52,770	57,627	(4,857)	52,917	48,626	4,292
November	108,186	121,449	(13,263)	84,054	101,932	(17,878)	57,958	74,843	(16,884)	57,776	65,305	(7,529)
December	108,710	124,624	(15,914)	86,977	108,153	(21,176)	58,332	68,999	(10,667)	59,967	71,643	(11,677)
Total:	1,311,444	1,385,143	(73,699)	1,059,133	1,184,530	(125,397)	704,377	776,445	(72,068)	670,819	723,091	(52,272)

OHL is aware that the Retail Transmission rates are subject to any modifications as a result of an OEB decision on Hydro One Networks' 2010 Uniform Transmission Rate Adjustment Application January 1, 2010.

OHL has examined the trends in the monthly balances in the RTSR deferral accounts.

OHL feels that the RTSR rates with the adjustment of the UTRs effective July 1, 2009 will eliminate the ongoing trends in the balances of the RTSR deferral accounts.

EXISTING RATE CLASSES:

Residential:

This classification refers to the supply of electrical energy to residential customers in detached or semi-detached units, as defined in the local zoning by-law.

General Service Less than 50 kW:

This classification refers to the supply of electrical energy to commercial buildings taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Commercial buildings are defined as buildings, which are used for purposes other than residential dwellings.

General Service 50 to 4999 kW:

This classification refers to the supply of electrical energy to commercial buildings whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Commercial buildings are defined as buildings, which are used for purposes other than residential dwellings.

Unmetered Scattered Load:

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Unmetered or flat connections are permitted with the approval of OHL’s Engineering Department. Flat rate connects may include, but are not limited to, Traffic Lights, Street Lights, Bus Shelters, and Signs. Energy consumption is determined by information provided by the customer and/or load measurement taken by OHL following connection of the flat service.

Sentinel Lighting:

This classification refers to an account for roadway lighting not classified as unmetered or street lighting. The consumption for the customer will be based on the calculated connected load times a twelve hour day times the applicable billing period.

Street Lighting:

This classification refers to the Street Lighting system owned by the Town of Orangeville, the Village of Grand Valley and the Ministry of Transportation and Communications.

EXISTING RATE SCHEDULE:

Orangeville Hydro Limited

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.07
Distribution Volumetric Rate	$/kWh	0.0135
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031
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	$	30.78
Distribution Volumetric Rate	$/kWh	0.0101
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0028
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	$	184.39
Distribution Volumetric Rate	$/kW	1.8266
Retail Transmission Rate – Network Service Rate	$/kW	1.9365
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1003
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 – Time of Use

Service Charge	$	2,142.44
Distribution Volumetric Rate	$/kW	1.7580
Retail Transmission Rate – Network Service Rate	$/kW	2.0543
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2160
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 customer)	$	29.78
Distribution Volumetric Rate	$/kWh	0.0101
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0028
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	0.40
Distribution Volumetric Rate	$/kW	1.9320
Retail Transmission Rate – Network Service Rate	$/kW	1.4678
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8684
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.04
Distribution Volumetric Rate	$/kW	0.6418
Retail Transmission Rate – Network Service Rate	$/kW	1.4605
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8505
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
Pulling post dated cheques	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque Charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect 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
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & 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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0406
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0302
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

EXISTING RATE SCHEDULE:

Grand Valley Energy

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.30
Distribution Volumetric Rate	$/kWh	0.0163
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
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	$	22.36
Distribution Volumetric Rate	$/kWh	0.0141
Retail Transmission Rate – Network Service Rate	$/kWh	0.0031
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	233.99
Distribution Volumetric Rate	$/kW	3.9508
Retail Transmission Rate – Network Service Rate	$/kW	1.1714
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7871
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 customer)	$	21.36
Distribution Volumetric Rate	$/kWh	0.0141
Retail Transmission Rate – Network Service Rate	$/kWh	0.0031
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.93
Distribution Volumetric Rate	$/kW	5.8417
Retail Transmission Rate – Network Service Rate	$/kW	1.1714
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7871
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
Returned Cheque (plus bank charges)	$	15.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0612
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0505
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

SCHEDULE OF PROPOSED RATES AND CHARGES:

Residential

Service Charge	**$**	17.46
Smart Meter Rate Adder		1.00
Distribution Volumetric Rate	**$/kWh**	0.0134
LV Charges	**$/kWh**	0.0009
Rate Rider	**$/kWh**	(0.0013)
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030
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	**$**	33.52
Smart Meter Rate Adder		1.00
Distribution Volumetric Rate	**$/kWh**	0.0103
LV Charges	**$/kWh**	0.0008
Rate Rider	**$/kWh**	(0.0013)
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0027
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	**$**	264.94
Smart Meter Rate Adder		1.00
Distribution Volumetric Rate	**$/kW**	1.8345
LV Charges	**$/kW**	0.3149
Rate Rider	**$/kW**	(0.5080)
Retail Transmission Rate – Network Service Rate	**$/kW**	1.9365
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.0761
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)	**$**	6.40
Distribution Volumetric Rate	**$/kWh**	0.0091
LV Charges	**$/kWh**	0.0008
Rate Rider	**$/kWh**	(0.0010)
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0027
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0013
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25

Sentinel Lighting

Service Charge (per connection)	**$**	1.91
Distribution Volumetric Rate	**$/kW**	7.4165
LV Charges	**$/kW**	0.2485
Rate Rider	**$/kW**	(0.4868)
Retail Transmission Rate – Network Service Rate	**$/kW**	1.4678
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8493
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0013
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25

Street Lighting

Service Charge (per connection)	**$**	0.81
Distribution Volumetric Rate	**$/kW**	4.4557
LV Charges	**$/kW**	0.2485
Rate Rider	**$/kW**	(0.4520)
Retail Transmission Rate – Network Service Rate	**$/kW**	1.4605
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8318
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
Request for other billing information	**$**	15.00
Income tax letter	**$**	15.00
Returned cheque charge (plus bank charges)	**$**	15.00
Legal letter charge	**$**	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	**$**	30.00
Special meter reads	**$**	30.00

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

Temporary service install & remove - overhead - no transformer	**$**	500.00
Install/Remove load control device - during regular hours	**$**	65.00
Install/Remove load control device - after regular hours	**$**	185.00
Specific Charge for Access to the Power Poles $/pole/year	**$**	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)
	$/kW	0.00
	$/kW	0.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0468
Total Loss Factor – Secondary Metered Customer > 5,000 kW	0.0000
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0363
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0134

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RECONCILIATION OF RATE CLASS REVENUE:

2010 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 2,104,524	$ 1,214,474		$ 3,318,997	$ 3,315,055
GS < 50 kW	$ 434,620	$ 432,400		$ 867,020	$ 865,709
GS >50 kW	$ 413,306	$ 630,156	($90,131)	$ 953,331	$ 953,344
GS >50 kW - TOU-eliminate	$ -	$ -	$0	$ -	$ -
Sentinel Lights	$ 3,889	$ 2,758		$ 6,647	$ 6,647
Street Lighting	$ 26,424	$ 23,974		$ 50,399	$ 50,400
USL	$ 11,601	$ 3,732		$ 15,333	$ 15,320
Back-up/Standby Power					
Total	**$ 2,994,365**	**$ 2,307,493**	**($90,131)**	**$ 5,211,727**	**$ 5,206,475**

Difference Due to Rate Rounding

-$ 5,252

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

Total Loss Factor:

OHL has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2004 to 2008. The calculations are summarized in Table 14 below.

Table 14
Total Loss Factor Calculations

Calculation for distribution loss adjustment factors

	Description	2004	2005	2006	2007	2008	Total
A	"Wholesale" kWh IESO plus Embedded Generation	249,629,277	258,210,340	259,662,833	265,059,732	257,950,545	1,290,512,727
B	"Wholesale" kWh for Large Use customer(s)	0	0	0	0	0	0
C	Net "Wholesale" kWh (A)-(B)	249,629,277	258,210,340	259,662,833	265,059,732	257,950,545	1,290,512,727
D	"Retail" kWh (Distributor)	242,286,509	249,806,945	250,897,683	256,622,372	249,716,485	1,249,329,994
E	"Retail" kWh for Large Use Customer(s)						0
F	Net "Retail" kWh (D)-(E)	242,286,509	249,806,945	250,897,683	256,622,372	249,716,485	1,249,329,994
G	Loss Factor [(C)/(F)]	103.03%	103.36%	103.49%	103.29%	103.30%	103.30%
H	Distribution Loss Adjustment Factor (5 year avg.)						**103.30%**
	Supply Facility Loss Factor	101.32%	101.28%	101.32%	101.34%	101.43%	101.34%
	Supply Facility Loss Adjustment Factor (3 year avg.)						**101.34%**
	Total Loss Factor						**1.0468**

Supply Facility Loss Factor:

The supply facility loss factor (the "SFLF") calculation is shown in Table 15 and represents the losses on supply to OHL. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF is used in the calculations of the total loss factor above based on the 2004 to 2008 averages.

Table 15
Supply Facility Loss Factor

Description	Full Year	Full Year	Full Year	Full Year	Full Year	Total
	2004	2005	2006	2007	2008	
"Wholesale" kWh IESO With Losses	252,917,856	261,520,105	263,090,888	268,617,931	261,643,455	1,307,790,235
"Wholesale" kWh IESO No Losses	249,629,277	258,210,340	259,662,833	265,059,732	257,950,545	1,290,512,727
Supply Facility Loss Factor	**0.01317**	**0.01282**	**0.01320**	**0.01342**	**0.01432**	**0.01339**

Total Loss Factor by Class:

Table 16 sets out the class-specific Loss Factors used by OHL in the calculation of commodity and other non-distribution charges.

Table 16
Total Loss Factor by Class

Total Utility Loss Adjustment Factor		LAF
Supply Facility Loss Factor		1.0134
Distribution Loss Factor		
Distribution Loss Factor - Secondary Metered Customer < 5,000kW		1.0330
Distribution Loss Factor - Primary Metered Customer < 5,000kW		1.0226
Total Loss Factor		
Total Loss Factor - Secondary Metered Customer < 5,000kW		1.0468
Total Loss Factor - Primary Metered Customer < 5,000kW		1.0363

Materiality Analysis on Distribution Losses:

OHL's Distribution Loss Adjustment factor is 3.30%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, OHL is not required to provide a explanation of, or justification for, its loss adjustment factor.

RATE AND BILL IMPACTS:

Appendix A to this Schedule presents the results of the assessment of customer total bill impacts by customer rate class.

Impacts are derived using the applicable May 1, 2009 rates and the proposed 2010 distribution rates, the proposed new Regulatory Asset rate rider, and the proposed revised loss factors. Electricity rates for Residential and General Service < 50 kW are the rates effective May 1, 2009 for Rate Protection Plan customers. Electricity rates for other classes are the forecasted rates for 2010 of $.0607/kWh.

In the residential class for Grand Valley there is an impact of 15.35% on the total bill for a customer with consumption of 100kWh. We researched and found 17 accounts that were affected. Out of these 17 accounts 14 accounts were empty apartment units, 2 were disconnected and 1 account was a garage.

There are no other bill impacts that exceed the 10% threshold other than the street light and sentinel light classes that were increased due to cost allocation.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

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APPENDIX A

TABLE OF RATE AND BILL IMPACTS

RESIDENTIAL

Consumption		2009 BILL			2010 BILL			IMPACT		
100 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			16.07			17.46	1.39	8.65%	59.38%
	Distribution (kWh)	100	0.0135	1.35	100	0.0143	1.43	0.08	5.93%	4.86%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	3.40%
	LRAM & SSM Rider (kWh)	100	0.0000	0.00	100	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	100	0.0000	0.00	100	(0.0013)	(0.13)	(0.13)	100.00%	(0.44%)
	Sub-Total			**18.42**			**19.76**	**1.34**	**7.29%**	**67.21%**
	Other Charges (kWh)	104	0.0218	2.27	105	0.0217	2.27	0.01	0.28%	7.74%
	Cost of Power Commodity (kWh)	104	0.0570	5.93	105	0.0570	5.97	0.04	0.59%	20.29%
	Total Bill Before Taxes			**26.62**			**28.00**	**1.38**	**5.20%**	**95.24%**
	GST		5.00%	1.33		5.00%	1.40	0.07	5.20%	4.76%
	Total Bill			**27.95**			**29.40**	**1.45**	**5.20%**	**100.00%**

RESIDENTIAL

Consumption		2009 BILL			2010 BILL			IMPACT		
250 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			16.07			17.46	1.39	8.65%	39.29%
	Distribution (kWh)	250	0.0135	3.38	250	0.0143	3.58	0.20	5.93%	8.05%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	2.25%
	LRAM & SSM Rider (kWh)	250			250	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	250	0.0000	0.00	250	(0.0013)	(0.32)	(0.32)	100.00%	(0.72%)
	Sub-Total			**20.45**			**21.71**	**1.27**	**6.21%**	**48.87%**
	Other Charges (kWh)	260	0.0218	5.67	262	0.0217	5.69	0.02	0.28%	12.80%
	Cost of Power Commodity (kWh)	260	0.0570	14.83	262	0.0570	14.92	0.09	0.59%	33.57%
	Total Bill Before Taxes			**40.95**			**42.32**	**1.37**	**3.35%**	**95.24%**
	GST		5.00%	2.05		5.00%	2.12	0.07	3.35%	4.76%
	Total Bill			**42.99**			**44.43**	**1.37**	**3.19%**	**100.00%**

RESIDENTIAL

Consumption		2009 BILL			2010 BILL			IMPACT		
500 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			16.07			17.46	1.39	8.65%	25.13%
	Distribution (kWh)	500	0.0135	6.75	500	0.0143	7.15	0.40	5.93%	10.29%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.44%
	LRAM & SSM Rider (kWh)	500			500	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	500	0.0000	0.00	500	(0.0013)	(0.64)	(0.64)	100.00%	(0.92%)
	Sub-Total			**23.82**			**24.97**	**1.15**	**4.83%**	**35.93%**
	Other Charges (kWh)	520	0.0218	11.34	523	0.0217	11.37	0.03	0.28%	16.37%
	Cost of Power Commodity (kWh)	520	0.0570	29.66	523	0.0570	29.83	0.18	0.59%	42.93%
	Total Bill Before Taxes			**64.82**			**66.18**	**1.36**	**2.09%**	**95.24%**
	GST		5.00%	3.24		5.00%	3.31	0.07	2.09%	4.76%
	Total Bill			**68.06**			**69.49**	**1.42**	**2.09%**	**100.00%**

RESIDENTIAL

Consumption		2009 BILL			2010 BILL			IMPACT		
600 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			16.07			17.46	1.39	8.65%	39.81%
	Distribution (kWh)	600	0.0135	8.10	600	0.0143	8.58	0.48	5.93%	19.56%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	2.28%
	LRAM & SSM Rider (kWh)	600			600	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	600	0.0000	0.00	600	(0.0013)	(0.77)	(0.77)	100.00%	(1.75%)
	Sub-Total			**25.17**			**26.27**	**1.10**	**4.38%**	**59.90%**
	Other Charges (kWh)	624	0.0218	13.61	628	0.0217	13.65	0.04	0.28%	31.12%
	Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	77.97%
	Cost of Power Commodity (kWh)	24	0.0660	1.61	28	0.0660	1.85	0.24	15.16%	4.22%
	Total Bill Before Taxes			**40.39**			**41.77**	**1.38**	**3.42%**	**95.24%**
	GST		5.00%	2.02		5.00%	2.09	0.07	3.42%	4.76%
	Total Bill			**42.41**			**43.86**	**1.45**	**3.42%**	**100.00%**

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Consumption
1,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			16.07			17.46	1.39	8.65%	14.10%
Distribution (kWh)	1,000	0.0135	13.50	1,000	0.0143	14.30	0.80	5.93%	11.55%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.81%
LRAM & SSM Rider (kWh)	1,000			1,000	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	(0.0013)	(1.28)	(1.28)	100.00%	(1.03%)
Sub-Total			**30.57**			**31.48**	**0.91**	**2.97%**	**25.42%**
Other Charges (kWh)	1,041	0.0218	22.69	1,047	0.0217	22.75	0.06	0.28%	18.37%
Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	27.62%
Cost of Power Commodity (kWh)	441	0.0660	29.08	447	0.0660	29.49	0.41	1.40%	23.82%
Total Bill Before Taxes			**116.54**			**117.92**	**1.38**	**1.18%**	**95.24%**
GST		5.00%	5.83		5.00%	5.90	0.07	1.18%	4.76%
Total Bill			**122.36**			**123.81**	**1.45**	**1.18%**	**100.00%**

RESIDENTIAL

Consumption
1,500 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			16.07			17.46	1.39	8.65%	9.76%
Distribution (kWh)	1,500	0.0135	20.25	1,500	0.0143	21.45	1.20	5.93%	11.99%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.56%
LRAM & SSM Rider (kWh)	1,500			1,500	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	1,500	0.0000	0.00	1,500	(0.0013)	(1.92)	(1.92)	100.00%	(1.07%)
Sub-Total			**37.32**			**37.99**	**0.67**	**1.79%**	**21.24%**
Other Charges (kWh)	1,561	0.0218	34.03	1,570	0.0217	34.12	0.09	0.28%	19.08%
Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	19.12%
Cost of Power Commodity (kWh)	961	0.0660	63.42	970	0.0660	64.03	0.61	0.96%	35.80%
Total Bill Before Taxes			**168.97**			**170.34**	**1.37**	**0.81%**	**95.24%**
GST		5.00%	8.45		5.00%	8.52	0.07	0.81%	4.76%
Total Bill			**177.42**			**178.86**	**1.44**	**0.81%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
2,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			29.78			33.52	3.74	12.56%	13.91%
Distribution (kWh)	2,000	0.0101	20.20	2,000	0.0111	22.20	2.00	9.90%	9.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.41%
Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	(0.0013)	(2.67)	(2.67)	100.00%	(1.11%)
Sub-Total			**50.98**			**54.05**	**3.07**	**6.02%**	**22.43%**
Other Charges (kWh)	2,081	0.0211	43.91	2,094	0.0210	44.05	0.13	0.30%	18.28%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	17.74%
Cost of Power Commodity (kWh)	1,331	0.0660	87.86	1,344	0.0660	88.68	0.81	0.93%	36.80%
Total Bill Before Taxes			**225.51**			**229.52**	**4.01**	**1.78%**	**95.24%**
GST		5.00%	11.28		5.00%	11.48	0.20	1.78%	4.76%
Total Bill			**236.78**			**241.00**	**4.21**	**1.78%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
4,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			29.78			33.52	3.74	12.56%	7.40%
Distribution (kWh)	4,000	0.0101	40.40	4,000	0.0111	44.40	4.00	9.90%	9.80%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.22%
Regulatory Assets (kWh)	4,000	0.0000	0.00	4,000	(0.0013)	(5.34)	(5.34)	100.00%	(1.18%)
Sub-Total			**71.18**			**73.58**	**2.40**	**3.36%**	**16.25%**
Other Charges (kWh)	4,163	0.0211	87.83	4,187	0.0210	88.09	0.26	0.30%	19.45%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	9.44%
Cost of Power Commodity (kWh)	3,413	0.0660	225.23	3,437	0.0660	226.85	1.63	0.72%	50.10%
Total Bill Before Taxes			**426.99**			**431.27**	**4.28**	**1.00%**	**95.24%**
GST		5.00%	21.35		5.00%	21.56	0.21	1.00%	4.76%
Total Bill			**448.34**			**452.83**	**4.50**	**1.00%**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			29.78			33.52	3.74	12.56%	3.08%
10,000 kWh	Distribution (kWh)	10,000	0.0101	101.00	10,000	0.0111	111.00	10.00	9.90%	10.20%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.09%
	Regulatory Assets (kWh)	10,000	0.0000	0.00	10,000	(0.0013)	(13.36)	(13.36)	100.00%	(1.23%)
	Sub-Total			**131.78**			**132.16**	**0.38**	**0.29%**	**12.14%**
	Other Charges (kWh)	10,406	0.0211	219.57	10,468	0.0210	220.23	0.65	0.30%	20.24%
	Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	3.93%
	Cost of Power Commodity (kWh)	9,656	0.0660	637.32	9,718	0.0660	641.38	4.06	0.64%	58.93%
	Total Bill Before Taxes			**1,031.42**			**1,036.52**	**5.10**	**0.49%**	**95.24%**
	GST		5.00%	51.57		5.00%	51.83	0.25	0.49%	4.76%
	Total Bill			**1,082.99**			**1,088.35**	**5.35**	**0.49%**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			29.78			33.52	3.74	12.56%	2.48%
12,500 kWh	Distribution (kWh)	12,500	0.0101	126.25	12,500	0.0111	138.75	12.50	9.90%	10.25%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.07%
	Regulatory Assets (kWh)	12,500	0.0000	0.00	12,500	(0.0013)	(16.70)	(16.70)	100.00%	(1.23%)
	Sub-Total			**157.03**			**156.57**	**(0.46)**	**(0.29%)**	**11.57%**
	Other Charges (kWh)	13,008	0.0211	274.47	13,085	0.0210	275.29	0.82	0.30%	20.34%
	Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	3.16%
	Cost of Power Commodity (kWh)	12,258	0.0660	809.02	12,335	0.0660	814.10	5.08	0.63%	60.16%
	Total Bill Before Taxes			**1,283.27**			**1,288.71**	**5.44**	**0.42%**	**95.24%**
	GST		5.00%	64.16		5.00%	64.44	0.27	0.42%	4.76%
	Total Bill			**1,347.43**			**1,353.14**	**5.71**	**0.42%**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			29.78			33.52	3.74	12.56%	2.07%
15,000 kWh	Distribution (kWh)	15,000	0.0101	151.50	15,000	0.0111	166.50	15.00	9.90%	10.29%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.06%
	Regulatory Assets (kWh)	15,000	0.0000	0.00	15,000	(0.0013)	(20.04)	(20.04)	100.00%	(1.24%)
	Sub-Total			**182.28**			**180.98**	**(1.30)**	**(0.72%)**	**11.19%**
	Other Charges (kWh)	15,610	0.0211	329.36	15,702	0.0210	330.34	0.98	0.30%	20.42%
	Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	2.64%
	Cost of Power Commodity (kWh)	14,860	0.0660	980.73	14,952	0.0660	986.83	6.10	0.62%	60.99%
	Total Bill Before Taxes			**1,535.12**			**1,540.89**	**5.78**	**0.38%**	**95.24%**
	GST		5.00%	76.76		5.00%	77.04	0.29	0.38%	4.76%
	Total Bill			**1,611.88**			**1,617.94**	**6.06**	**0.38%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			183.39			264.94	81.55	44.47%	18.62%
11,000 kWh	Distribution (kWh)	11,000	0.0000	0.00	11,000	0.0000	0.00	0.00	0.00%	0.00%
50 kW	Distribution (kW)	50	1.8266	91.33	50	2.1494	107.47	16.14	17.67%	7.55%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.07%
	Regulatory Assets (kW)	50	0.0000	0.00	50	(0.5080)	(25.40)	(25.40)	100.00%	(1.78%)
	Sub-Total			**275.72**			**348.01**	**72.29**	**26.22%**	**24.46%**
	Other Charges (kWh)	11,447	0.0135	154.53	11,515	0.0135	155.45	0.91	0.59%	10.92%
	Other Charges (kW)	52	3.0368	158.01	52	3.0126	156.75	(1.26)	(0.80%)	11.02%
	Cost of Power Commodity (kWh)	11,447	0.0607	695.06	11,447	0.0607	695.06	0.00	0.00%	48.84%
	Total Bill Before Taxes			**1,283.32**			**1,355.27**	**71.95**	**5.61%**	**95.24%**
	GST		5.00%	64.17		5.00%	67.76	3.60	5.61%	4.76%
	Total Bill			**1,347.49**			**1,423.03**	**75.54**	**5.61%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			183.39			264.94	81.55	44.47%	2.73%
100,000 kWh	Distribution (kWh)	100,000	0.0000	0.00	100,000	0.0000	0.00	0.00	0.00%	0.00%
250 kW	Distribution (kW)	250	1.8266	456.65	250	2.1494	537.35	80.70	17.67%	5.54%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.01%
	Regulatory Assets (kW)	250	0.0000	0.00	250	(0.5080)	(126.99)	(126.99)	100.00%	(1.31%)
	Sub-Total			**641.04**			**676.30**	**35.26**	**5.50%**	**6.98%**
	Other Charges (kWh)	104,063	0.0135	1,404.86	104,679	0.0135	1,413.17	8.31	0.59%	14.58%
	Other Charges (kW)	260	3.0368	790.05	262	3.0126	788.39	(1.66)	(0.21%)	8.13%
	Cost of Power Commodity (kWh)	104,063	0.0607	6,316.65	104,679	0.0607	6,354.04	37.38	0.59%	65.55%
	Total Bill Before Taxes			**9,152.60**			**9,231.89**	**79.30**	**0.87%**	**95.24%**
	GST		5.00%	457.63		5.00%	461.59	3.96	0.87%	4.76%
	Total Bill			**9,610.23**			**9,693.49**	**83.26**	**0.87%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			183.39			264.94	81.55	44.47%	1.38%
210,000 kWh	Distribution (kWh)	210,000	0.0000	0.00	210,000	0.0000	0.00	0.00	0.00%	0.00%
360 kW	Distribution (kW)	360	1.8266	657.58	360	2.1494	773.78	116.21	17.67%	4.03%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.01%
	Regulatory Assets (kW)	360	0.0000	0.00	360	(0.5080)	(182.87)	(182.87)	100.00%	(0.95%)
	Sub-Total			**841.97**			**856.85**	**14.89**	**1.77%**	**4.46%**
	Other Charges (kWh)	218,533	0.0135	2,950.20	219,827	0.0135	2,967.66	17.46	0.59%	15.44%
	Other Charges (kW)	375	3.0368	1,137.67	377	3.0126	1,135.28	(2.39)	(0.21%)	5.91%
	Cost of Power Commodity (kWh)	218,533	0.0607	13,264.97	219,827	0.0607	13,343.47	78.50	0.59%	69.43%
	Total Bill Before Taxes			**18,194.81**			**18,303.27**	**108.46**	**0.60%**	**95.24%**
	GST		5.00%	909.74		5.00%	915.16	5.42	0.60%	4.76%
	Total Bill			**19,104.55**			**19,218.43**	**113.89**	**0.60%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			183.39			264.94	81.55	44.47%	0.72%
400,000 kWh	Distribution (kWh)	400,000	0.0000	0.00	400,000	0.0000	0.00	0.00	0.00%	0.00%
800 kW	Distribution (kW)	800	1.8266	1,461.28	800	2.1494	1,719.52	258.24	17.67%	4.66%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
	Regulatory Assets (kW)	800	0.0000	0.00	800	(0.5080)	(406.38)	(406.38)	100.00%	(1.10%)
	Sub-Total			**1,645.67**			**1,579.08**	**(66.59)**	**(4.05%)**	**4.28%**
	Other Charges (kWh)	416,254	0.0135	5,619.43	418,717	0.0135	5,652.68	33.26	0.59%	15.31%
	Other Charges (kW)	833	3.0368	2,528.16	837	3.0126	2,522.85	(5.31)	(0.21%)	6.83%
	Cost of Power Commodity (kWh)	416,254	0.0607	25,266.61	418,717	0.0607	25,416.14	149.53	0.59%	68.82%
	Total Bill Before Taxes			**35,059.86**			**35,170.76**	**110.89**	**0.32%**	**95.24%**
	GST		5.00%	1,752.99		5.00%	1,758.54	5.54	0.32%	4.76%
	Total Bill			**36,812.86**			**36,929.30**	**116.44**	**0.32%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			183.39			264.94	81.55	44.47%	0.35%
855,000 kWh	Distribution (kWh)	855,000	0.0000	0.00	855,000	0.0000	0.00	0.00	0.00%	0.00%
1,755 kW	Distribution (kW)	1,755	1.8266	3,205.68	1,755	2.1494	3,772.20	566.51	17.67%	4.94%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
	Transformer Credit	4,000	(0.6000)	(2,400.00)	4,000	(0.6000)	(2,400.00)	0.00	0.00%	(3.14%)
	Regulatory Assets (kW)	1,755	0.0000	0.00	1,755	(0.5080)	(891.49)	(891.49)	100.00%	(1.17%)
	Sub-Total			**990.07**			**746.65**	**(243.43)**	**(24.59%)**	**0.98%**
	Other Charges (kWh)	889,743	0.0135	12,011.53	895,008	0.0135	12,082.61	71.09	0.59%	15.83%
	Other Charges (kW)	1,826	3.0368	5,546.15	1,837	3.0126	5,534.50	(11.65)	(0.21%)	7.25%
	Cost of Power Commodity (kWh)	889,743	0.0607	54,007.38	895,008	0.0607	54,327.00	319.62	0.59%	71.18%
	Total Bill Before Taxes			**72,555.12**			**72,690.76**	**135.64**	**0.19%**	**95.24%**
	GST		5.00%	3,627.76		5.00%	3,634.54	6.78	0.19%	4.76%
	Total Bill			**76,182.88**			**76,325.30**	**142.42**	**0.19%**	**100.00%**

Street Lighting

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	2,602	0.0400	104.08	2,602	0.81	2,103.46	1,999.38	1,921.00%	12.19%
2,602 Connections	Distribution (kWh)	141,913	0.0000	0.00	141,913	0.0000	0.00	0.00	0.00%	0.00%
141,913 kWh	Distribution (kW)	379	0.6418	243.43	379	4.6991	1,782.37	1,538.93	632.18%	10.33%
379 kW	Regulatory Assets (kW)	379	0.0000	0.00	379	(0.4492)	(170.40)	(170.40)	100.00%	(0.99%)
	Sub-Total			**347.51**			**3,715.43**	**3,367.91**	**969.14%**	**21.54%**
	Other Charges (kWh)	147,679	0.0135	1,993.67	148,553	0.0135	2,005.47	11.80	0.59%	11.63%
	Other Charges (kW)	395	2.3110	912.18	397	2.2923	910.15	(2.03)	(0.22%)	5.28%
	Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	0.25%
	Cost of Power Commodity (kWh)	146,929	0.0660	9,697.34	147,803	0.0660	9,755.02	57.68	0.59%	56.55%
	Total Bill Before Taxes			**12,993.45**			**16,428.82**	**3,435.36**	**26.44%**	**95.24%**
	GST		5.00%	649.67		5.00%	821.44	171.77	26.44%	4.76%
	Total Bill			**13,643.13**			**17,250.26**	**3,607.13**	**26.44%**	**100.00%**

Street Lighting

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	1	0.0400	0.04	1	0.81	0.81	0.77	1,921.00%	12.74%
1 Connections	Distribution (kWh)	55	0.0000	0.00	55	0.0000	0.00	0.00	0.00%	0.00%
54.54 kWh	Distribution (kW)	0.15	0.6418	0.10	0.15	4.6991	0.70	0.61	632.18%	11.11%
0.15 kW	Regulatory Assets (kW)	0.15	0.0000	0.00	0.15	(0.4492)	(0.07)	(0.07)	100.00%	(1.06%)
	Sub-Total			**0.14**			**1.45**	**1.31**	**961.04%**	**22.79%**
	Other Charges (kWh)	57	0.0135	0.77	57	0.0135	0.77	0.00	0.59%	12.15%
	Other Charges (kW)	0.16	2.3110	0.36	0.16	2.2923	0.36	(0.00)	(0.22%)	5.67%
	Cost of Power Commodity (kWh)	57	0.0607	3.45	57	0.0607	3.47	0.02	0.59%	54.62%
	Total Bill Before Taxes			**4.71**			**6.04**	**1.33**	**28.33%**	**95.24%**
	GST		5.00%	0.24		5.00%	0.30	0.07	28.33%	4.76%
	Total Bill			**4.94**			**6.34**	**1.40**	**28.33%**	**100.00%**

Sentinel Lighting

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	177	0.4000	70.80	177	1.91	337.33	266.53	376.45%	20.31%
177 Connections	Distribution (kWh)	12,062	0.0000	0.00	12,062	0.0000	0.00	0.00	0.00%	0.00%
12,062 kWh	Distribution (kW)	32	1.9320	61.82	32	7.6650	245.28	183.46	296.74%	14.77%
32 kW	Regulatory Assets (kW)	32	0.0000	0.00	32	(0.4833)	(15.46)	(15.46)	100.00%	(0.93%)
	Sub-Total			**132.62**			**567.14**	**434.52**	**327.63%**	**34.15%**
	Other Charges (kWh)	12,552	0.0135	169.45	12,626	0.0135	170.45	1.00	0.59%	10.26%
	Other Charges (kW)	33	2.3362	77.80	33	2.3171	77.62	(0.18)	(0.23%)	4.67%
	Cost of Power Commodity (kWh)	12,552	0.0607	761.89	12,626	0.0607	766.40	4.51	0.59%	46.15%
	Total Bill Before Taxes			**1,141.76**			**1,581.61**	**439.85**	**38.52%**	**95.24%**
	GST		5.00%	57.09		5.00%	79.08	21.99	38.52%	4.76%
	Total Bill			**1,198.85**			**1,660.69**	**461.84**	**38.52%**	**100.00%**

Sentinel Lighting

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Billing Determinants	Monthly Service Charge	1	0.4000	0.40	1	1.91	1.91	1.51	376.45%	20.33%
1 Connections	Distribution (kWh)	68	0.0000	0.00	68	0.0000	0.00	0.00	0.00%	0.00%
68.15 kWh	Distribution (kW)	0.18	1.9320	0.35	0.18	7.6650	1.38	1.03	296.74%	14.72%
0.18 kW	Regulatory Assets (kW)	0.18	0.0000	0.00	0.18	(0.4833)	(0.09)	(0.09)	100.00%	(0.93%)
	Sub-Total			**0.75**			**3.20**	**2.45**	**327.75%**	**34.12%**
	Other Charges (kWh)	71	0.0135	0.96	71	0.0135	0.96	0.01	0.59%	10.27%
	Other Charges (kW)	0.19	2.3362	0.44	0.19	2.3171	0.44	(0.00)	(0.23%)	4.66%
	Cost of Power Commodity (kWh)	71	0.0607	4.30	71	0.0607	4.33	0.03	0.59%	46.19%
	Total Bill Before Taxes			**6.45**			**8.93**	**2.48**	**38.48%**	**95.24%**
	GST		5.00%	0.32		5.00%	0.45	0.12	38.48%	4.76%
	Total Bill			**6.77**			**9.37**	**2.60**	**38.48%**	**100.00%**

Unmetered Scattered

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge	1	29.7800	29.78	57	6.4024	364.94	335.16	1,125.44%	10.06%
57 Connections	Distribution (kWh)	32,685	0.0101	330.12	32,685	0.0099	323.58	(6.54)	(1.98%)	8.92%
32,685 kWh	Regulatory Assets (kW)	0	0.0000	0.00	32,685	(0.0010)	(31.42)	(31.42)	100.00%	(0.87%)
	Sub-Total			**359.90**			**657.11**	**297.20**	**82.58%**	**18.12%**
	Other Charges (kWh)	34,013	0.0211	717.68	34,215	0.0210	719.82	2.14	0.30%	19.85%
	Cost of Power Commodity (kWh)	34,013	0.0607	2,064.61	34,215	0.0607	2,076.83	12.22	0.59%	57.27%
	Total Bill Before Taxes			**3,142.19**			**3,453.76**	**311.56**	**9.92%**	**95.24%**
	GST		5.00%	157.11		5.00%	172.69	15.58	9.92%	4.76%
	Total Bill			**3,299.30**			**3,626.44**	**327.14**	**9.92%**	**100.00%**

Unmetered Scattered

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge	1	29.7800	29.78	1	6.4024	6.40	(23.38)	(78.50%)	23.08%
1 Connections	Distribution (kWh)	214	0.0101	2.16	214	0.0099	2.12	(0.04)	(1.98%)	7.64%
214 kWh	Regulatory Assets (kW)	0	0.0000	0.00	214	(0.0010)	(0.21)	(0.21)	100.00%	(0.74%)
	Sub-Total			**31.94**			**8.32**	**(23.63)**	**(73.97%)**	**29.97%**
	Other Charges (kWh)	223	0.0211	4.70	224	0.0210	4.71	0.01	0.30%	16.99%
	Cost of Power Commodity (kWh)	223	0.0607	13.52	224	0.0607	13.60	0.08	0.59%	49.02%
	Total Bill Before Taxes			**50.16**			**26.42**	**(23.74)**	**(47.33%)**	**95.24%**
	GST		5.00%	2.51		5.00%	1.32	(1.19)	(47.33%)	4.76%
	Total Bill			**52.67**			**27.74**	**(24.92)**	**(47.33%)**	**100.00%**

GRAND VALLEY RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			13.30			17.46	4.16	31.28%	59.38%
100 kWh	Distribution (kWh)	100	0.0163	1.63	100	0.0143	1.43	(0.20)	(12.27%)	4.86%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	3.40%
	LRAM & SSM Rider (kWh)	100	0.0000	0.00	100	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	100	0.0000	0.00	100	(0.0013)	(0.13)	(0.13)	100.00%	(0.44%)
	Sub-Total			**15.93**			**19.76**	**3.83**	**24.05%**	**67.21%**
	Other Charges (kWh)	106	0.0219	2.32	105	0.0217	2.27	(0.05)	(2.11%)	7.74%
	Cost of Power Commodity (kWh)	106	0.0570	6.05	105	0.0570	5.97	(0.08)	(1.35%)	20.29%
	Total Bill Before Taxes			**24.30**			**28.00**	**3.70**	**15.23%**	**95.24%**
	GST		5.00%	1.22		5.00%	1.40	0.19	15.23%	4.76%
	Total Bill			**25.52**			**29.40**	**3.89**	**15.23%**	**100.00%**

RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			13.30			17.46	4.16	31.28%	39.29%
250 kWh	Distribution (kWh)	250	0.0163	4.08	250	0.0143	3.58	(0.50)	(12.27%)	8.05%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	2.25%
	LRAM & SSM Rider (kWh)	250	0.0000	0.00	250	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	250	0.0000	0.00	250	(0.0013)	(0.32)	(0.32)	100.00%	(0.72%)
	Sub-Total			**18.38**			**21.71**	**3.34**	**18.18%**	**48.87%**
	Other Charges (kWh)	265	0.0219	5.81	262	0.0217	5.69	(0.12)	(2.11%)	12.80%
	Cost of Power Commodity (kWh)	265	0.0570	15.12	262	0.0570	14.92	(0.20)	(1.35%)	33.57%
	Total Bill Before Taxes			**39.31**			**42.32**	**3.01**	**7.66%**	**95.24%**
	GST		5.00%	1.97		5.00%	2.12	0.15	7.66%	4.76%
	Total Bill			**41.27**			**44.43**	**3.01**	**7.30%**	**100.00%**

RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			13.30			17.46	4.16	31.28%	25.13%
500 kWh	Distribution (kWh)	500	0.0163	8.15	500	0.0143	7.15	(1.00)	(12.27%)	10.29%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.44%
	LRAM & SSM Rider (kWh)	500	0.0000	0.00	500	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	500	0.0000	0.00	500	(0.0013)	(0.64)	(0.64)	100.00%	(0.92%)
	Sub-Total			**22.45**			**24.97**	**2.52**	**11.22%**	**35.93%**
	Other Charges (kWh)	531	0.0219	11.62	523	0.0217	11.37	(0.25)	(2.11%)	16.37%
	Cost of Power Commodity (kWh)	531	0.0570	30.24	523	0.0570	29.83	(0.41)	(1.35%)	42.93%
	Total Bill Before Taxes			**64.31**			**66.18**	**1.86**	**2.90%**	**95.24%**
	GST		5.00%	3.22		5.00%	3.31	0.09	2.90%	4.76%
	Total Bill			**67.53**			**69.49**	**1.96**	**2.90%**	**100.00%**

RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			13.30			17.46	4.16	31.28%	39.81%
600 kWh	Distribution (kWh)	600	0.0163	9.78	600	0.0143	8.58	(1.20)	(12.27%)	19.56%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	2.28%
	LRAM & SSM Rider (kWh)	600	0.0000	0.00	600	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	600	0.0000	0.00	600	(0.0013)	(0.77)	(0.77)	100.00%	(1.75%)
	Sub-Total			**24.08**			**26.27**	**2.19**	**9.10%**	**59.90%**
	Other Charges (kWh)	637	0.0219	13.94	628	0.0217	13.65	(0.29)	(2.11%)	31.12%
	Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	77.97%
	Cost of Power Commodity (kWh)	37	0.0660	2.42	28	0.0660	1.85	(0.57)	(23.48%)	4.22%
	Total Bill Before Taxes			**40.45**			**41.77**	**1.33**	**3.28%**	**95.24%**
	GST		5.00%	2.02		5.00%	2.09	0.07	3.28%	4.76%
	Total Bill			**42.47**			**43.86**	**1.39**	**3.28%**	**100.00%**

RESIDENTIAL

Consumption
800 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			13.30			17.46	4.16	31.28%	17.15%
Distribution (kWh)	800	0.0163	13.04	800	0.0143	11.44	(1.60)	(12.27%)	11.24%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.98%
LRAM & SSM Rider (kWh)	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	800	0.0000	0.00	800	(0.0013)	(1.02)	(1.02)	100.00%	(1.01%)
Sub-Total			**27.34**			**28.88**	**1.54**	**5.62%**	**28.37%**
Other Charges (kWh)	849	0.0219	18.59	837	0.0217	18.20	(0.39)	(2.11%)	17.88%
Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	33.60%
Cost of Power Commodity (kWh)	249	0.0660	16.43	237	0.0660	15.67	(0.76)	(4.62%)	15.39%
Total Bill Before Taxes			**96.56**			**96.94**	**0.38**	**0.40%**	**95.24%**
GST		5.00%	4.83		5.00%	4.85	0.02	0.40%	4.76%
Total Bill			**101.39**			**101.79**	**0.40**	**0.40%**	**100.00%**

RESIDENTIAL

Consumption
1,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			13.30			17.46	4.16	31.28%	14.10%
Distribution (kWh)	1,000	0.0163	16.30	1,000	0.0143	14.30	(2.00)	(12.27%)	11.55%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.81%
LRAM & SSM Rider (kWh)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	(0.0013)	(1.28)	(1.28)	100.00%	(1.03%)
Sub-Total			**30.60**			**31.48**	**0.88**	**2.87%**	**25.42%**
Other Charges (kWh)	1,061	0.0219	23.24	1,047	0.0217	22.75	(0.49)	(2.11%)	18.37%
Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	27.62%
Cost of Power Commodity (kWh)	461	0.0660	30.44	447	0.0660	29.49	(0.95)	(3.11%)	23.82%
Total Bill Before Taxes			**118.48**			**117.92**	**(0.56)**	**(0.47%)**	**95.24%**
GST		5.00%	5.92		5.00%	5.90	(0.03)	(0.47%)	4.76%
Total Bill			**124.40**			**123.81**	**(0.59)**	**(0.47%)**	**100.00%**

RESIDENTIAL

Consumption
1,500 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			13.30			17.46	4.16	31.28%	9.76%
Distribution (kWh)	1,500	0.0163	24.45	1,500	0.0143	21.45	(3.00)	(12.27%)	11.99%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.56%
LRAM & SSM Rider (kWh)	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	1,500	0.0000	0.00	1,500	(0.0013)	(1.92)	(1.92)	100.00%	(1.07%)
Sub-Total			**38.75**			**37.99**	**(0.76)**	**(1.96%)**	**21.24%**
Other Charges (kWh)	1,592	0.0219	34.86	1,570	0.0217	34.12	(0.74)	(2.11%)	19.08%
Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	19.12%
Cost of Power Commodity (kWh)	992	0.0660	65.45	970	0.0660	64.03	(1.42)	(2.17%)	35.80%
Total Bill Before Taxes			**173.26**			**170.34**	**(2.92)**	**(1.68%)**	**95.24%**
GST		5.00%	8.66		5.00%	8.52	(0.15)	(1.68%)	4.76%
Total Bill			**181.93**			**178.86**	**(3.06)**	**(1.68%)**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
2,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			21.36			33.52	12.16	56.93%	13.91%
Distribution (kWh)	2,000	0.0141	28.20	2,000	0.0111	22.20	(6.00)	(21.28%)	9.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.41%
Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	(0.0013)	(2.67)	(2.67)	100.00%	(1.11%)
Sub-Total			**50.56**			**54.05**	**3.49**	**6.90%**	**22.43%**
Other Charges (kWh)	2,081	0.0211	43.91	2,094	0.0210	44.05	0.13	0.30%	18.28%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	17.74%
Cost of Power Commodity (kWh)	1,331	0.0660	87.86	1,344	0.0660	88.68	0.81	0.93%	36.80%
Total Bill Before Taxes			**225.09**			**229.52**	**4.43**	**1.97%**	**95.24%**
GST		5.00%	11.25		5.00%	11.48	0.22	1.97%	4.76%
Total Bill			**236.34**			**241.00**	**4.65**	**1.97%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
4,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			21.36			33.52	12.16	56.93%	7.40%
Distribution (kWh)	4,000	0.0141	56.40	4,000	0.0111	44.40	(12.00)	(21.28%)	9.80%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.22%
Regulatory Assets (kWh)	4,000	0.0000	0.00	4,000	(0.0013)	(5.34)	(5.34)	100.00%	(1.18%)
Sub-Total			**78.76**			**73.58**	**(5.18)**	**(6.58%)**	**16.25%**
Other Charges (kWh)	4,163	0.0211	87.83	4,187	0.0210	88.09	0.26	0.30%	19.45%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	9.44%
Cost of Power Commodity (kWh)	3,413	0.0660	225.23	3,437	0.0660	226.85	1.63	0.72%	50.10%
Total Bill Before Taxes			**434.57**			**431.27**	**(3.30)**	**(0.76%)**	**95.24%**
GST		5.00%	21.73		5.00%	21.56	(0.16)	(0.76%)	4.76%
Total Bill			**456.30**			**452.83**	**(3.46)**	**(0.76%)**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
10,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			21.36			33.52	12.16	56.93%	3.08%
Distribution (kWh)	10,000	0.0141	141.00	10,000	0.0111	111.00	(30.00)	(21.28%)	10.20%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.09%
Regulatory Assets (kWh)	10,000	0.0000	0.00	10,000	(0.0013)	(13.36)	(13.36)	100.00%	(1.23%)
Sub-Total			**163.36**			**132.16**	**(31.20)**	**(19.10%)**	**12.14%**
Other Charges (kWh)	10,406	0.0211	219.57	10,468	0.0210	220.23	0.65	0.30%	20.24%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	3.93%
Cost of Power Commodity (kWh)	9,656	0.0660	637.32	9,718	0.0660	641.38	4.06	0.64%	58.93%
Total Bill Before Taxes			**1,063.00**			**1,036.52**	**(26.48)**	**(2.49%)**	**95.24%**
GST		5.00%	53.15		5.00%	51.83	(1.32)	(2.49%)	4.76%
Total Bill			**1,116.15**			**1,088.35**	**(27.81)**	**(2.49%)**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
12,500 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			21.36			33.52	12.16	56.93%	2.48%
Distribution (kWh)	12,500	0.0141	176.25	12,500	0.0111	138.75	(37.50)	(21.28%)	10.25%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.07%
Regulatory Assets (kWh)	12,500	0.0000	0.00	12,500	(0.0013)	(16.70)	(16.70)	100.00%	(1.23%)
Sub-Total			**198.61**			**156.57**	**(42.04)**	**(21.17%)**	**11.57%**
Other Charges (kWh)	13,008	0.0211	274.47	13,085	0.0210	275.29	0.82	0.30%	20.34%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	3.16%
Cost of Power Commodity (kWh)	12,258	0.0660	809.02	12,335	0.0660	814.10	5.08	0.63%	60.16%
Total Bill Before Taxes			**1,324.85**			**1,288.71**	**(36.14)**	**(2.73%)**	**95.24%**
GST		5.00%	66.24		5.00%	64.44	(1.81)	(2.73%)	4.76%
Total Bill			**1,391.09**			**1,353.14**	**(37.95)**	**(2.73%)**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
15,000 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			21.36			33.52	12.16	56.93%	2.07%
Distribution (kWh)	15,000	0.0141	211.50	15,000	0.0111	166.50	(45.00)	(21.28%)	10.29%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.06%
Regulatory Assets (kWh)	15,000	0.0000	0.00	15,000	(0.0013)	(20.04)	(20.04)	100.00%	(1.24%)
Sub-Total			**233.86**			**180.98**	**(52.88)**	**(22.61%)**	**11.19%**
Other Charges (kWh)	15,610	0.0211	329.36	15,702	0.0210	330.34	0.98	0.30%	20.42%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	2.64%
Cost of Power Commodity (kWh)	14,860	0.0660	980.73	14,952	0.0660	986.83	6.10	0.62%	60.99%
Total Bill Before Taxes			**1,586.70**			**1,540.89**	**(45.80)**	**(2.89%)**	**95.24%**
GST		5.00%	79.33		5.00%	77.04	(2.29)	(2.89%)	4.76%
Total Bill			**1,666.03**			**1,617.94**	**(48.09)**	**(2.89%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
2,175 kWh
60 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			232.99			264.94	31.95	13.71%	35.33%
Distribution (kWh)	2,175	0.0000	0.00	2,175	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	60	3.9508	237.05	60	2.1494	128.96	(108.08)	(45.60%)	17.20%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.13%
Regulatory Assets (kW)	60	0.0000	0.00	60	(0.5080)	(30.48)	(30.48)	100.00%	(4.06%)
Sub-Total			**471.04**			**364.43**	**(106.61)**	**(22.63%)**	**48.60%**
Other Charges (kWh)	2,308	0.0135	31.16	2,277	0.0135	30.74	(0.42)	(1.35%)	4.10%
Other Charges (kW)	60	2.9585	177.51	60	3.0126	180.76	3.25	1.83%	24.10%
Cost of Power Commodity (kWh)	2,308	0.0607	140.14	2,277	0.0607	138.25	(1.90)	(1.35%)	18.44%
Total Bill Before Taxes			**819.85**			**714.16**	**(105.68)**	**(12.89%)**	**95.24%**
GST		5.00%	40.99		5.00%	35.71	(5.28)	(12.89%)	4.76%
Total Bill			**860.84**			**749.87**	**(110.97)**	**(12.89%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
6,450 kWh
65 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			232.99			264.94	31.95	13.71%	23.59%
Distribution (kWh)	6,450	0.0000	0.00	6,450	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	65	3.9508	256.80	65	2.1494	139.71	(117.09)	(45.60%)	12.44%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.09%
Regulatory Assets (kW)	65	0.0000	0.00	65	(0.5080)	(33.02)	(33.02)	100.00%	(2.94%)
Sub-Total			**490.79**			**372.63**	**(118.16)**	**(24.08%)**	**33.18%**
Other Charges (kWh)	6,844	0.0135	92.40	6,752	0.0135	91.15	(1.25)	(1.35%)	8.12%
Other Charges (kW)	65	2.9585	192.30	65	3.0126	195.82	3.52	1.83%	17.44%
Cost of Power Commodity (kWh)	6,844	0.0607	415.59	6,752	0.0607	409.97	(5.62)	(1.35%)	36.51%
Total Bill Before Taxes			**1,191.09**			**1,069.57**	**(121.52)**	**(10.20%)**	**95.24%**
GST		5.00%	59.55		5.00%	53.48	(6.08)	(10.20%)	4.76%
Total Bill			**1,250.64**			**1,123.05**	**(127.59)**	**(10.20%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
15,280 kWh
60 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			232.99			264.94	31.95	13.71%	14.57%
Distribution (kWh)	15,280	0.0000	0.00	15,280	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	60	3.9508	237.05	60	2.1494	128.96	(108.08)	(45.60%)	7.09%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.05%
Regulatory Assets (kW)	60	0.0000	0.00	60	(0.5080)	(30.48)	(30.48)	100.00%	(1.68%)
Sub-Total			**471.04**			**364.43**	**(106.61)**	**(22.63%)**	**20.03%**
Other Charges (kWh)	16,214	0.0135	218.89	15,995	0.0135	215.93	(2.96)	(1.35%)	11.87%
Other Charges (kW)	60	2.9585	177.51	60	3.0126	180.76	3.25	1.83%	9.94%
Cost of Power Commodity (kWh)	16,214	0.0607	984.54	15,995	0.0607	971.22	(13.32)	(1.35%)	53.39%
Total Bill Before Taxes			**1,851.98**			**1,732.33**	**(119.65)**	**(6.46%)**	**95.24%**
GST		5.00%	92.60		5.00%	86.62	(5.98)	(6.46%)	4.76%
Total Bill			**1,944.58**			**1,818.95**	**(125.64)**	**(6.46%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
40,000 kWh
125 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			232.99			264.94	31.95	13.71%	6.38%
Distribution (kWh)	40,000	0.0000	0.00	40,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	125	3.9508	493.85	125	2.1494	268.68	(225.18)	(45.60%)	6.47%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.02%
Regulatory Assets (kW)	125	0.0000	0.00	125	(0.5080)	(63.50)	(63.50)	100.00%	(1.53%)
Sub-Total			**727.84**			**471.12**	**(256.72)**	**(35.27%)**	**11.34%**
Other Charges (kWh)	42,446	0.0135	573.02	41,872	0.0135	565.27	(7.75)	(1.35%)	13.61%
Other Charges (kW)	125	2.9585	369.81	125	3.0126	376.57	6.76	1.83%	9.07%
Cost of Power Commodity (kWh)	42,446	0.0607	2,577.33	41,872	0.0607	2,542.45	(34.88)	(1.35%)	61.22%
Total Bill Before Taxes			**4,248.01**			**3,955.41**	**(292.59)**	**(6.89%)**	**95.24%**
GST		5.00%	212.40		5.00%	197.77	(14.63)	(6.89%)	4.76%
Total Bill			**4,460.41**			**4,153.18**	**(307.22)**	**(6.89%)**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			232.99			264.94	31.95	13.71%	12.72%
47,000 kWh	Distribution (kWh)	47,000	0.0000	0.00	47,000	0.0000	0.00	0.00	0.00%	0.00%
100 kW	Distribution (kW)	100	3.9508	395.08	100	2.1494	214.94	(180.14)	(45.60%)	10.32%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.05%
	Transformer Credit	4,000	(0.6000)	(2,400.00)	4,000	(0.6000)	(2,400.00)	0.00	0.00%	(115.27%)
	Regulatory Assets (kW)	100	0.0000	0.00	100	(0.5080)	(50.80)	(50.80)	100.00%	(2.44%)
	Sub-Total			**(1,770.93)**			**(1,969.92)**	**(198.99)**	**11.24%**	**(94.61%)**
	Other Charges (kWh)	49,874	0.0135	673.30	49,199	0.0135	664.19	(9.11)	(1.35%)	31.90%
	Other Charges (kW)	100	2.9585	295.85	100	3.0126	301.26	5.41	1.83%	14.47%
	Cost of Power Commodity (kWh)	49,874	0.0607	3,028.36	49,199	0.0607	2,987.38	(40.98)	(1.35%)	143.48%
	Total Bill Before Taxes			**2,226.59**			**1,982.91**	**(243.67)**	**(10.94%)**	**95.24%**
	GST		5.00%	111.33		5.00%	99.15	(12.18)	(10.94%)	4.76%
	Total Bill			**2,337.91**			**2,082.06**	**(255.86)**	**(10.94%)**	**100.00%**

Street Lighting

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	152	0.9300	141.36	152	0.8084	122.88	(18.48)	(13.08%)	11.59%
152 Connections	Distribution (kWh)	8,863	0.0000	0.00	8,863	0.0000	0.00	0.00	0.00%	0.00%
8,863 kWh	Distribution (kW)	24	5.8417	139.62	24	4.6991	112.31	(27.31)	(19.56%)	10.59%
24 kW	Regulatory Assets (kW)	24	0.0000	0.00	24	(0.4520)	(10.80)	(10.80)	100.00%	(1.02%)
	Sub-Total			**280.98**			**224.38**	**(56.59)**	**(20.14%)**	**21.16%**
	Other Charges (kWh)	9,405	0.0135	126.97	9,278	0.0135	125.25	(1.72)	(1.35%)	11.81%
	Other Charges (kW)	24	2.9585	70.71	24	2.2923	54.79	(15.92)	(22.52%)	5.17%
	Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	4.03%
	Cost of Power Commodity (kWh)	8,655	0.0660	571.23	8,528	0.0660	562.83	(8.40)	(1.47%)	53.07%
	Total Bill Before Taxes			**1,092.63**			**1,010.00**	**(82.63)**	**(7.56%)**	**95.24%**
	GST		5.00%	54.63		5.00%	50.50	(4.13)	(7.56%)	4.76%
	Total Bill			**1,147.26**			**1,060.50**	**(86.77)**	**(7.56%)**	**100.00%**

Street Lighting

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	1	0.9300	0.93	1	0.8084	0.81	(0.12)	(13.08%)	9.48%
1 Connections	Distribution (kWh)	58	0.0000	0.00	58	0.0000	0.00	0.00	0.00%	0.00%
58.30 kWh	Distribution (kW)	0.46	5.8417	2.69	0.46	4.6991	2.16	(0.53)	(19.56%)	25.36%
0.46 kW	Regulatory Assets (kW)	0.46	0.0000	0.00	0.46	(0.4520)	(0.21)	(0.21)	100.00%	(2.44%)
	Sub-Total			**3.62**			**2.76**	**(0.86)**	**(23.64%)**	**32.40%**
	Other Charges (kWh)	62	0.0135	0.84	61	0.0135	0.82	(0.01)	(1.35%)	9.66%
	Other Charges (kW)	0.46	2.9585	1.36	0.46	2.2923	1.05	(0.31)	(22.52%)	12.37%
	Cost of Power Commodity (kWh)	62	0.0570	3.53	61	0.0570	3.48	(0.05)	(1.35%)	40.80%
	Total Bill Before Taxes			**9.34**			**8.12**	**(1.22)**	**(13.07%)**	**95.24%**
	GST		5.00%	0.47		5.00%	0.41	(0.06)	(13.07%)	4.76%
	Total Bill			**9.81**			**8.52**	**(1.28)**	**(13.07%)**	**100.00%**

Unmetered Scattered

Billing Determinants
3 Connections
1,496.00 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	3	21.36	64.08	3	6.40	19.21	(44.87)	(70.03%)	11.82%
Distribution (kWh)	1,496	0.0141	21.09	1,496	0.0099	14.81	(6.28)	(29.79%)	9.11%
Regulatory Assets (kW)	0	0.0000	0.00	1,496	(0.0010)	(1.44)	(1.44)	100.00%	(0.88%)
Sub-Total			**85.17**			**32.58**	**(52.59)**	**(61.75%)**	**20.05%**
Other Charges (kWh)	1,587	0.0211	33.50	1,566	0.0210	32.95	(0.55)	(1.64%)	20.27%
Cost of Power Commodity (kWh)	1,587	0.0570	90.49	1,566	0.0570	89.26	(1.22)	(1.35%)	54.92%
Total Bill Before Taxes			**209.16**			**154.79**	**(54.37)**	**(25.99%)**	**95.24%**
GST		5.00%	10.46		5.00%	7.74	(2.72)	(25.99%)	4.76%
Total Bill			**219.61**			**162.53**	**(57.09)**	**(25.99%)**	**100.00%**

Unmetered Scattered

Billing Determinants
1 Connections
498.67 kWh

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	1	21.36	21.36	1	6.40	6.40	(14.96)	(70.03%)	11.93%
Distribution (kWh)	499	0.0141	7.03	499	0.0099	4.94	(2.09)	(29.79%)	9.20%
Regulatory Assets (kW)	0	0.0000	0.00	499	(0.0010)	(0.48)	(0.48)	100.00%	(0.89%)
Sub-Total			**28.39**			**10.86**	**(17.53)**	**(61.75%)**	**20.23%**
Other Charges (kWh)	529	0.0216	11.43	522	0.0210	10.98	(0.45)	(3.92%)	20.46%
Cost of Power Commodity (kWh)	529	0.0570	30.16	522	0.0570	29.75	(0.41)	(1.35%)	55.44%
Total Bill Before Taxes			**69.98**			**51.12**	**(18.87)**	**(26.96%)**	**95.24%**
GST		5.00%	3.50		5.00%	2.56	(0.94)	(26.96%)	4.76%
Total Bill			**73.48**			**53.67**	**(19.81)**	**(26.96%)**	**100.00%**

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS & BALANCES:

This Schedule contains descriptions of Deferral and Variance Accounts (“DVAs”) currently used by OHL and their balances as at December 31, 2008.

GROUP 1 ACCOUNTS

1550 Retail Settlement Variance Account – Low Voltage Charges

Description: This account is used to record the net of the amount charged by the host distributor to an embedded distributor and the amount billed to customers based on OHL’s approved LV rates. OHL uses the billed method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. OHL uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Transmission Network Charge. OHL uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge. OHL uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1588 Retail Settlement Variance Account – Power

Description: This account is used to recover the net difference between the energy amount billed to customers and the energy charge to OHL using the settlement invoice from the Independent Electricity System Operator (“IESO”). OHL uses the accrual method and has used this method consistently over time for the applicable period. The variance between Board-approved and actual line losses is reflected in Account 15880 for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustments

Description: This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to OHL using the settlement invoice from the IESO. OHL uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1590 Recovery of Regulatory Asset Balances

Description: This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. This Regulatory Asset rate rider was removed from Distribution Rates effective May 1, 2008. OHL followed the Board's instructions and made entries to clear the balances of each account. Separate sub-accounts are maintained for expenses, interest, and recovery amounts. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

GROUP 2 ACCOUNTS

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Description: This account includes amounts paid for OEB Cost Assessment for the period January 1, 2004 to April 30, 2006 in excess of amounts previously included in rates (1999 OEB costs). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1508 Other Regulatory Assets - Sub-account Pension Contributions

Description: This account includes amounts paid for OMERS pension expense for the period January 1, 2004 to April 30, 2006 not included in rates. An interest rate of 3.88% per annum was calculated in recorded in a sub-account.

1555 Smart Meter Capital and Recovery Offset Variance

Description: This account records the net of the amounts paid for capitalized direct costs related to the smart meter program and the amounts charged to customers using the OEB-approved smart meter rate rider. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. OHL is following the Smart Meter Funding and Cost Recovery Guideline dated October 22, 2008 (G-2008-0002) and therefore not requesting recovery.

1556 Smart Meter OM&A Variance

Description: This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. OHL is following the Smart Meter Funding and Cost Recovery Guideline dated October 22, 2008 (G-2008-0002) and therefore not requesting recovery.

1562 Deferred Payments in Lieu of Taxes

Description: 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 periods ending April 30, 2006. OHL is not requesting recovery of this account and waiting for the result of the combined PILs proceeding (EB-2008-0381)

1563 Contra Account-Deferred Payments in Lieu of Taxes

Description: This account records the amount resulting from the OEB-approved PILs methodology using the third accounting method. The offsetting entry made to account 1562 was made to this contra account. OHL is not requesting recovery of this account and waiting for the result of the combined PILs proceeding (EB-2008-0381)

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

Description: This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB-approved rate. OHL uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

ACCOUNT BALANCES

The following Table 1 contains account balances from the 2008 Audited Financial Statements as at December 31, 2008.

TABLE 1 - OHL DECEMBER 31, 2008 REGULATORY ASSETS

Account Description	Account Number	Principal Amounts as of Dec-31 2008	Interest to Dec31-08	Total Principal & Interest
RSVA - Wholesale Market Service Charge	1580	$ (578,941)	$ (29,042)	$ (607,983)
RSVA - One-time Wholesale Market Service	1582	$ 13,829	$ 2,158	$ 15,988
RSVA - Retail Transmission Network Charge	1584	$ (291,326)	$ (23,201)	$ (314,526)
RSVA - Retail Transmission Connection Charge	1586	$ (727,817)	$ (83,474)	$ (811,291)
RSVA - Power	1588	$ 176,570	$ 11,294	$ 187,864
Sub-Totals		$ (1,407,684)	$ (122,264)	$ (1,529,949)
Other Regulatory Assets	1508	$ 97,531	$ 16,399	$ 113,930
Retail Cost Variance Account - Retail	1518	$ (12,913)	$ -	$ (12,913)
Retail Cost Variance Account - STR	1548	$ (2,401)	$ -	$ (2,401)
Smart Meters Revenue and Capital	1555	$ (52,214)	$ (3,620)	$ (55,834)
Smart Meter Expenses	1556			$ -
Low Voltage	1550	$ 98,861	$ 7,626	$ 106,486
Transition Costs	1570	$ (10,879)	$ (1,382)	$ (12,260)
Regulatory Asset Recovery	1590	$ 64,442	$ (48,396)	$ 16,045
Sub-Totals		$ 182,427	$ (29,373)	$ 153,054
Total Regulatory Assets		$ (1,225,258)	$ (151,637)	$ (1,376,895)

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

OHL is requesting disposition of the variance accounts noted below according to the Report of the Board EB-2008-0046 issued July 31, 2009.

OHL has followed the guidelines in the Report of the Board however rather than using the default disposition period of one year OHL is requesting disposition over a four-year period. There is a large credit due to the customers and disposition over one year would result in a rate rider of ($.0050) for a residential customer. A rate rider of this amount would create a rate impact in the following year 2011 IRM rate adjustment. A four year period would reduce rate shock and even out this amount if considered over a four year period. These funds have also been building up over the last 4 years (2004 to 2008) and recovery over a four year period would match the accumulation period. OHL has provided a continuity schedule of the accounts listed below in Appendix A of this exhibit.

1580 Wholesale Market Service Charges

Disposal of balances as at April 30, 2010 amounting to ($618,250) over a four-year period is requested.

Method of recovery: Allocation to rate classes on basis of kilowatt hours.

1582 One Time Charges

Disposal of balances as at April 30, 2010 amounting to $16,233 over a four-year period is requested.

Method of recovery: Allocation to rate classes on basis of kilowatt hours.

1584 Transmission Network

Disposal of balances as at April 30, 2010 amounting to ($319,692) over a four-year period is requested.

Method of recovery: Allocation to rate classes on basis of kilowatt hours.

1586 Transmission Connection

Disposal of balances as at April 30, 2010 amounting to ($824,198) over a four-year period is requested.

Method of recovery: Allocation to rate classes on basis of kilowatt hours.

1588 Power Variance

Disposal of balances as at April 30, 2010 amounting to $190,995 over a four-year period is requested.

Method of recovery: Allocation to rate classes on basis of kilowatt hours.

1588 Power Variance - Global Adjustment

Disposal of balances as at April 30, 2010 amounting to $99,504 over a four-year period is requested.

Method of recovery: Allocation to non-RPP customers in the >50 General Service Class on basis of kilowatt hours.

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Disposal of balances as at April 30, 2010 amounting to $34,496 over a four-year period is requested.

Method of recovery: Allocation to rate classes on basis of distribution revenue.

1508 Other Regulatory Assets - Sub-account Pension Costs

Disposal of balances as at April 30, 2010 amounting to $79,434 over a four-year period is requested.

Method of recovery: Allocation to rate classes on basis of distribution revenue.

1518 Retail Cost Variance Account

Disposal of balances as at April 30, 2010 amounting to $(13,142) over a four-year period is requested.

Method of Recovery: Allocation to rate classes on basis of number of customers.

1548 Miscellaneous Deferred Debits

Disposal of balances as at April 30, 2010 amounting to $(2,444) over a four-year period is requested.

Method of Recovery: Allocation to rate classes on basis of number of customers.

1570 Transition Costs

Disposal of balances as at April 30, 2010 amounting to $(12,453) over a four-year period is requested. There is a small credit balance in this account due to some of the deregulation costs for software that were not subject to PST.

Method of Recovery: Allocation to rate classes on basis of number of customers.

1550 Low Voltage Costs

Disposal of balances recorded in April 30, 2010 amounting to $108,239 over a four-year period is requested.

Method of Recovery: Allocation to rate classes on basis of kilowatt hours.

1590 Regulatory Asset Recovery Ending April 30, 2006

Disposal of balances recorded in April 30, 2010 amounting to $17,188 over a four-year period is requested. OHL notes that the Board typically does not allow for recovery until the final balances are verified. Due to the low materiality of the balance, OHL would suggest it appropriate at this time to include with the recovery of all variances.

Method of Recovery: Allocation to rate classes on basis of in proportion to recovery share.

SMART METERS

OHL is not requesting clearance of the smart meter variance accounts at this time. OHL is proposing to continue using the current approved smart meter adder of $1.00 per meter per month for 2010 rates. OHL’s schedule for deployment of smart meters is the fall of 2009. Once smart meters are fully deployed and all costs are in, OHL will come forward with a smart meter rate rider application to dispose of the smart meter deferral and variance accounts and collect the cost of the smart meters as if they were in the rate base.

The balances as of December 31, 2008 and the forecasted interest through April 30, 2010 totaling ($1,242,359) are presented in the following table. The Annual Interest Rate of 1.33% is based on the Q3 2009 prescribed rates by the Ontario Energy Board. The average rate was calculated based on the first quarter of 2009.

TABLE 2 - OHL ACCOUNTS REQUESTED FOR DISPOSITION

Account Description	Account Number	Principal Amounts as of Dec-31 2008	Interest to Dec31-08	Interest Jan-1 to Dec31-09	Interest Jan1-10 to Apr30-10	Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (578,941)	$ (29,042)	$ (7,700)	$ (2,567)	$ (618,250)
RSVA - One-time Wholesale Market Service	1582	$ 13,829	$ 2,158	$ 184	$ 61	$ 16,233
RSVA - Retail Transmission Network Charge	1584	$ (291,326)	$ (23,201)	$ (3,875)	$ (1,292)	$ (319,692)
RSVA - Retail Transmission Connection Charge	1586	$ (727,817)	$ (83,474)	$ (9,680)	$ (3,227)	$ (824,198)
RSVA - Power	1588-1	$ 176,570	$ 11,294	$ 2,348	$ 783	$ 190,995
RSVA - Power-GA	1588-2	$ 97,771	$ -	$ 1,300	$ 433	$ 99,504
Sub-Totals		$ (1,309,914)	$ (122,264)	$ (17,422)	$ (5,807)	$ (1,455,407)
Other Regulatory Assets	1508	$ 97,531	$ 16,399	$ 1,297	$ 432	$ 115,660
Retail Cost Variance Account - Retail	1518	$ (12,913)	$ -	$ (172)	$ (57)	$ (13,142)
Retail Cost Variance Account - STR	1548	$ (2,401)	$ -	$ (32)	$ (11)	$ (2,444)
Smart Meters Revenue and Capital	1555			$ -	$ -	$ -
Smart Meter Expenses	1556			$ -	$ -	$ -
Low Voltage	1550	$ 98,861	$ 7,626	$ 1,315	$ 438	$ 108,239
Transition Costs	1570	$ (10,879)	$ (1,382)	$ (145)	$ (48)	$ (12,453)
Regulatory Asset Recovery	1590	$ 64,442	$ (48,396)	$ 857	$ 286	$ 17,188
Sub-Totals		$ 234,641	$ (25,753)	$ 3,121	$ 1,040	$ 213,048
Totals per column		$ (1,075,273)	$ (148,018)	$ (14,301)	$ (4,767)	$ (1,242,359)

Annual interest rate: 1.33%

Enter the appropriate 2010 data in the cells below.
Once the data in the yellow fields on Sheet 1 has been entered, the relevant allocations will appear on Sheet 2.
Go to Sheets 3 and 4 and enter the appropriate data in the yellow cells.

2010 Data By Class	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS		84,928,233	10,045		$ 3,239,709
GENERAL SERVICE <50 KW CLASS		38,954,924	1,081		$ 834,494
GENERAL SERVICE >50 KW NON TIME OF USE	293,178	122,840,423	133		$ 861,026
GENERAL SERVICE >50 KW TIME OF USE					
STANDBY					
LARGE USER CLASS					
UNMETERED & SCATTERED LOADS		151	33	32	$ 15,018
SENTINEL LIGHTS	360	129,899	46	170	$ 6,558
STREET LIGHTING	5,102	1,798,732	3	2,724	$ 49,159
Totals	298,639	248,652,361	11,340	2,926	$ 5,005,962

Allocators	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS	0.0%	34.2%	88.6%	0.0%	64.7%
GENERAL SERVICE <50 KW CLASS	0.0%	15.7%	9.5%	0.0%	16.7%
GENERAL SERVICE >50 KW NON TIME OF USE	98.2%	49.4%	1.2%	0.0%	17.2%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%	0.0%
STANDBY	0.0%	0.0%	0.0%	0.0%	0.0%
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%	0.0%
UNMETERED & SCATTERED LOADS	0.0%	0.0%	0.3%	1.1%	0.3%
SENTINEL LIGHTS	0.1%	0.1%	0.4%	5.8%	0.1%
STREET LIGHTING	1.7%	0.7%	0.0%	93.1%	1.0%
Totals	100%	100%	100%	100%	100%

The following shows the details and calculations of the proposed regulatory asset rate rider by customer classification.

Table 3 - Method of Disposition of Accounts

Deferral and Variance Accounts:	**Amount**	**ALLOCATOR**	**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**Small Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**
WMSC - Account 1580	($618,250)	kWh	$ (211,166)	$ (96,858)	$ (305,431)	$ (0)	$ (323)	$ (4,472)	$ (618,250)
One-Time WMSC - Account 1582	$16,233	kWh	$ 5,544	$ 2,543	$ 8,020	$ 0	$ 8	$ 117	$ 16,233
Network - Account 1584	($319,692)	kWh	$ (109,192)	$ (50,084)	$ (157,936)	$ (0)	$ (167)	$ (2,313)	$ (319,692)
Connection - Account 1586	($824,198)	kWh	$ (281,508)	$ (129,122)	$ (407,174)	$ (1)	$ (431)	$ (5,962)	$ (824,198)
Power - Account 1588-1	$190,995	kWh	$ 65,235	$ 29,922	$ 94,356	$ 0	$ 100	$ 1,382	$ 190,995
Power GA - Account 1588-2	$99,504	kWh-Non RPP			$ 99,504				
Subtotal - RSVA	($1,455,407)		$ (531,086)	$ (243,599)	$ (668,661)	$ (1)	$ (812)	$ (11,248)	$ (1,554,912)
Other Regulatory Assets - Account 1508	$115,660	Dx Revenue	$ 74,852	$ 19,281	$ 19,894	$ 347	$ 152	$ 1,136	$ 115,660
Retail Cost Variance Account - Acct 1518	($13,142)	# of Customers	$ (11,640)	$ (1,252)	$ (154)	$ (38)	$ (53)	$ (3)	$ (13,142)
Retail Cost Variance Account (STR) Acct 1548	($2,444)	# of Customers	$ (2,165)	$ (233)	$ (29)	$ (7)	$ (10)	$ (1)	$ (2,444)
Transition Costs - Account 1570	($12,453)	# of Customers	$ (11,031)	$ (1,187)	$ (146)	$ (36)	$ (51)	$ (3)	$ (12,453)
Low Voltage - Account 1550	$108,239	kWh	$ 36,970	$ 16,957	$ 53,473	$ 0	$ 57	$ 783	$ 108,239
Regulatory Asset Recovery - Acct 1590	$17,188	Proportion to Recovery Share	$ 11,124	$ 2,865	$ 2,956	$ 52	$ 23	$ 169	$ 17,188
Subtotal - Non RSVA, Variable	$213,048		$ 98,109	$ 36,431	$ 75,994	$ 317	$ 117	$ 2,080	$ 213,048
Smart Meters Revenue and Capital, 1555 (Fixed)		# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Expenses, 1556 (Fixed)		# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA Fixed	$0		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total to be Recovered	($1,242,359)		$ (432,977)	$ (207,168)	$ (592,667)	$ 316	$ (695)	$ (9,168)	$ (1,242,359)
Balance to be collected or refunded, Variable	$ (1,242,359)		$ (432,977)	$ (207,168)	$ (592,667)	$ 316	$ (695)	$ (9,168)	$ (1,242,359)
Balance to be collected or refunded, Fixed	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Number of years for Variable	4								
Number of years for Fixed	4								
Balance to be collected or refunded per year, Variable	$ (310,590)		$ (108,244)	$ (51,792)	$ (148,167)	$ 79	$ (174)	$ (2,292)	$ (310,590)

Class			**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Deferral and Variance Account Rate Riders, Variable			$ (0.0013)	$ (0.0013)	$ (0.5054)	$ 0.5233	$ (0.4833)	$ (0.4492)
Billing Determinants			kWh	kWh	kW	kWh	kW	kW
	Components of 2010 Riders:							
	Variable	RSVA	$ (0.0016)	$ (0.0016)	$ (0.5702)	$ (0.0016)	$ (0.5644)	$ (0.5512)
	Variable	Non RSVA	$ 0.0003	$ 0.0002	$ 0.0648	$ 0.0006	$ 0.0812	$ 0.1019
	Total Rate Rider		**$ (0.0013)**	**$ (0.0013)**	**$ (0.5054)**	**$ (0.0010)**	**$ (0.4833)**	**$ (0.4492)**

Proposed Rates and Bill Impacts:

The proposed rates and bill impacts that result from the disposal of the balances, as requested, are set out in Table 4 below.

TABLE 4

PROPOSED RATES AND BILL IMPACTS

Customer Class	Deferral and Variance Account Rate Riders ($) per kWh	Deferral and Variance Account Rate Riders ($) per kW	Bill Impacts
Residential	(0.0013)		-1.00%
GS < 50 kW	(0.0013)		-1.10%
GS >50 kW		(0.5054)	-0.95%
Sentinel Lights		(0.4833)	-0.93%
Street Lighting		(0.4492)	-0.99%
USL	(0.0010)		-0.86%

The above impacts were calculated based on the assumptions below:

Residential	-	800 kWh
GS <50 kW	-	2,000 kWh
GS >50 kW	-	500kW
Sentinel Lights	-	32 kW
Street Lighting	-	379 kW
USL	-	32,685 kWh

APPENDIX A- REGULATORY ASSET CONTINUITY SCHEDULE

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Orangeville Hydro Limited	**LICENCE NUMBER**	ED-XXXX-XXXX
NAME OF CONTACT	Jan Howard	**DOCID NUMBER**	EB-200X-XXXX

		2005							
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05 [1]**	**Transactions (additions) during 2005, excluding interest and adjustments [6]**	**Adjustments during 2005 - instructed by Board [2]**	**Adjustments during 2005 - other [3]**	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
RSVA - Wholesale Market Service Charge	1580	$ 268,463	$ 176,672			$ 445,135	$ 37,968	$ 21,636	$ 59,604
RSVA - One-time Wholesale Market Service	1582	$ 29,741	$ 13,585			$ 43,326	$ 2,421	$ 2,530	$ 4,951
RSVA - Retail Transmission Network Charge	1584	$ (186,255)	$ (120,595)			$ (306,851)	$ (8,012)	$ (17,523)	$ (25,535)
RSVA - Retail Transmission Connection Charge	1586	$ (842,352)	$ (311,987)			$ (1,154,339)	$ (100,019)	$ (80,544)	$ (180,562)
RSVA - Power	1588	$ (204,465)	$ (136,315)			$ (340,780)	$ (40,105)	$ (30,531)	$ (70,636)
Sub-Totals		$ (934,869)	$ (378,640)	$ -	$ -	$ (1,313,509)	$ (107,746)	$ (104,432)	$ (212,179)
Other Regulatory Assets - Sub-Account - OEB Cost Assessmer	1508	$ 13,206	$ 22,452	$ -	$ -	$ 35,658	$ 190	$ 788	$ 978
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ 70,133	$ -	$ -	$ 70,133	$ -	$ -	$ -
Retail Cost Variance Account - Retail	1518	$ 22,593	$ 789	$ -	$ -	$ 23,382	$ -	$ 1,638	$ 1,638
Retail Cost Variance Account - STR	1548	$ 1,722	$ (214)	$ -	$ -	$ 1,508	$ -	$ 125	$ 125
Misc. Deferred Debits	1525	$ 27,305	$ 2,168	$ -	$ -	$ 29,473	$ 2,537	$ 2,150	$ 4,687
LV Variance Account	1550	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Accou	1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Rec	1565	$ 1,038	$ (201,107)	$ -	$ -	$ (200,069)	$ -	$ -	$ -
CDM Contra	1566	$ (1,038)	$ 201,107	$ -	$ -	$ 200,069	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ 211,560	n/a	$ (27,759)	$ 28	$ 183,829	$ 28,545	$ 32,639	$ 61,184
Pre-Market Opening Energy Variances Total [5]	1571	$ 295,129	n/a	$ -	$ -	$ 295,129	$ 40,720	$ 20,477	$ 61,197
Extra-Ordinary Event Costs	1572	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Regulatory Asset Recovery	1590	$ (125,029)	$ (110,885)	$ -	$ -	$ (235,914)	$ (2,727)	$ (12,823)	$ (15,550)
Sub-Totals		$ 446,486	$ (15,557)	$ (27,759)	$ 28	$ 403,198	$ 69,265	$ 44,994	$ 114,259
Total		$ (488,383)	$ (394,197)	$ (27,759)	$ 28	$ (910,311)	$ (38,482)	$ (59,438)	$ (97,920)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ 16,559			$ 16,559	$ -	$ -	$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Orangeville Hydro Limited
NAME OF CONTACT Jan Howard

		2006										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-06**	**Transactions (additions) during 2006, excluding interest and adjustments [6]**	**Transactions (reductions) during 2006, excluding interest and adjustments [6]**	**Adjustments during 2006 - instructed by Board [2]**	**Adjustments during 2006 - other [3]**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**	**Interest Jan-1 to Dec31-06**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-06**
RSVA - Wholesale Market Service Charge	1580	$ 445,135	$ (303,325)				$ (332,717)	$ (190,907)	$ 59,604	$ 6,394	$ 340	$ 66,338
RSVA - One-time Wholesale Market Service	1582	$ 43,326	$ 244				$ (35,037)	$ 8,534	$ 4,951	$ 1,299	$ -	$ 6,250
RSVA - Retail Transmission Network Charge	1584	$ (306,851)	$ (43,881)				$ 283,673	$ (67,059)	$ (25,535)	$ (10,356)	$ 1,204	$ (34,688)
RSVA - Retail Transmission Connection Charge	1586	$ (1,154,339)	$ 2,149				$ 744,126	$ (408,064)	$ (180,562)	$ (39,568)	$ (1,153)	$ (221,284)
RSVA - Power	1588	$ (340,780)	$ 231,980				$ 269,723	$ 160,923	$ (70,636)	$ (5,453)	$ (5,671)	$ (81,759)
Sub-Totals		$ (1,313,509)	$ (112,833)	$ -	$ -	$ -	$ 929,768	$ (496,574)	$ (212,179)	$ (47,684)	$ (5,280)	$ (265,143)
Other Regulatory Assets - Sub-Account - OEB Cost Assessmer	1508	$ 35,658	$ 29,990	$ -	$ -	$ -	$ (35,841)	$ 29,807	$ 978	$ 2,498	$ (1,147)	$ 2,329
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 70,133	$ (2,409)	$ -	$ -	$ -	$ -	$ 67,724	$ -	$ 5,036	$ -	$ 5,036
Retail Cost Variance Account - Retail	1518	$ 23,382	$ (253)	$ -	$ -	$ -	$ (24,777)	$ (1,648)	$ 1,638	$ 546	$ -	$ 2,184
Retail Cost Variance Account - STR	1548	$ 1,508	$ (794)	$ -	$ -	$ -	$ (1,889)	$ (1,175)	$ 125	$ 42	$ -	$ 167
Misc. Deferred Debits	1525	$ 29,473	$ -	$ -	$ -	$ -	$ (29,473)	$ -	$ 4,687	$ -	$ (4,687)	$ -
LV Variance Account	1550	$ -	$ 59,816	$ -	$ -	$ -	$ -	$ 59,816	$ -	$ 1,028	$ -	$ 1,028
Smart Meter Capital and Recovery Offset Variance - Sub-Accou	1555	$ -	$ (20,897)	$ -	$ -	$ -	$ -	$ (20,897)	$ -	$ (241)	$ -	$ (241)
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Rec	1565	$ (200,069)	$ 4,622	$ -	$ -	$ -	$ -	$ (195,447)	$ -	$ -	$ -	$ -
CDM Contra	1566	$ 200,069	$ (4,622)	$ -	$ -	$ -	$ -	$ 195,447	$ -	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ 183,829	n/a	n/a	$ -	$ -	$ (194,708)	$ (10,879)	$ 61,184	$ (526)	$ (61,184)	$ (526)
Pre-Market Opening Energy Variances Total [5]	1571	$ 295,129	n/a	n/a	$ -	$ -	$ (295,129)	$ -	$ 61,197	$ 6,826	$ (68,023)	$ -
Extra-Ordinary Event Costs	1572	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Regulatory Asset Recovery	1590	$ (235,914)	$ (586,095)	$ -	$ -	$ -	$ 400,495	$ (421,514)	$ (15,550)	$ (21,768)	$ -	$ (37,318)
Sub-Totals		$ 403,198	$ (520,642)	$ -	$ -	$ -	$ (181,321)	$ (298,766)	$ 114,259	$ (6,558)	$ (135,041)	$ (27,340)
Total		$ (910,311)	$ (633,475)	$ -	$ -	$ -	$ 748,447	$ (795,339)	$ (97,920)	$ (54,242)	$ (140,321)	$ (292,483)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 16,559	$ 201,065				$ -	$ 217,624	$ -	$ -		$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Orangeville Hydro Limited
NAME OF CONTACT Jan Howard

		2007										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-07**	**Transactions (additions) during 2007, excluding interest and adjustments [6]**	**Transactions (reductions) during 2007, excluding interest and adjustments [6]**	**Adjustments during 2007 - instructed by Board [2]**	**Adjustments during 2007 - other [3]**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec31-07**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-07**
RSVA - Wholesale Market Service Charge	1580	$ (190,907)	$ (254,467)				$ -	$ (445,374)	$ 66,338	$ (143)	$ (75,550)	$ (9,355)
RSVA - One-time Wholesale Market Service	1582	$ 8,534	$ 5,296				$ -	$ 13,829	$ 6,250	$ 24	$ (4,666)	$ 1,608
RSVA - Retail Transmission Network Charge	1584	$ (67,059)	$ (94,695)				$ (4,175)	$ (165,929)	$ (34,688)	$ 1,541	$ 18,175	$ (14,972)
RSVA - Retail Transmission Connection Charge	1586	$ (408,064)	$ (283,994)				$ 16,513	$ (675,545)	$ (221,284)	$ (3,646)	$ 169,216	$ (55,714)
RSVA - Power	1588	$ 160,923	$ 80,974				$ -	$ 241,897	$ (81,759)	$ (3,543)	$ 79,121	$ (6,182)
Sub-Totals		$ (496,574)	$ (546,885)	$ -	$ -	$ -	$ 12,338	$ (1,031,121)	$ (265,143)	$ (5,768)	$ 186,295	$ (84,615)
Other Regulatory Assets - Sub-Account - OEB Cost Assessmer	1508	$ 29,807	$ -	$ -	$ -	$ -	$ -	$ 29,807	$ 2,329	$ 1,409	$ -	$ 3,739
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 67,724	$ -	$ -	$ -	$ -	$ -	$ 67,724	$ 5,036	$ 3,471	$ -	$ 8,508
Retail Cost Variance Account - Retail	1518	$ (1,648)	$ (6,202)	$ -	$ -	$ -	$ 2,184	$ (5,666)	$ 2,184	$ -	$ (2,184)	$ -
Retail Cost Variance Account - STR	1548	$ (1,175)	$ (811)	$ -	$ -	$ -	$ 167	$ (1,819)	$ 167	$ -	$ (167)	$ -
Misc. Deferred Debits	1525	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LV Variance Account	1550	$ 59,816	$ 16,474	$ -	$ -	$ -	$ -	$ 76,291	$ 1,028	$ 3,023	$ -	$ 4,052
Smart Meter Capital and Recovery Offset Variance - Sub-Accou	1555	$ (20,897)	$ (18,484)	$ -	$ -	$ -	$ -	$ (39,381)	$ (241)	$ (1,675)	$ -	$ (1,917)
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Rec	1565	$ (195,447)	$ 180,379	$ -	$ -	$ -	$ -	$ (15,068)	$ -	$ -	$ -	$ -
CDM Contra	1566	$ 195,447	$ (180,379)	$ -	$ -	$ -	$ -	$ 15,068	$ -	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ (10,879)	n/a	n/a	$ -	$ -	$ -	$ (10,879)	$ (526)	$ (341)	$ -	$ (867)
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extra-Ordinary Event Costs	1572	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Regulatory Asset Recovery	1590	$ (421,514)	$ 347,372	$ -	$ -	$ -	$ -	$ (74,142)	$ (37,318)	$ 8,294	$ (20,401)	$ (49,425)
Sub-Totals		$ (298,766)	$ 338,349	$ -	$ -	$ -	$ 2,351	$ 41,934	$ (27,340)	$ 14,181	$ (22,752)	$ (35,911)
Total		$ (795,339)	$ (208,536)	$ -	$ -	$ -	$ 14,689	$ (989,186)	$ (292,483)	$ 8,413	$ 163,543	$ (120,527)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 217,624	$ (200,521)					$ 17,102	$ -			$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Orangeville Hydro Limited
NAME OF CONTACT Jan Howard

		2008										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-08**	**Transactions (additions) during 2008, excluding interest and adjustments [6]**	**Transactions (reductions) during 2008, excluding interest and adjustments [6]**	**Adjustments during 2008 - instructed by Board [2]**	**Adjustments during 2008 - other [3]**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-08**	**Opening Interest Amounts as of Jan-1-08**	**Interest Jan-1 to Dec31-08**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-08**
RSVA - Wholesale Market Service Charge	1580	$ (445,374)	$ (133,567)					$ (578,941)	$ (9,355)	$ (19,687)		$ (29,042)
RSVA - One-time Wholesale Market Service	1582	$ 13,829	$ -					$ 13,829	$ 1,608	$ 550		$ 2,158
RSVA - Retail Transmission Network Charge	1584	$ (165,929)	$ (125,397)					$ (291,326)	$ (14,972)	$ (8,229)		$ (23,201)
RSVA - Retail Transmission Connection Charge	1586	$ (675,545)	$ (52,272)					$ (727,817)	$ (55,714)	$ (27,760)		$ (83,474)
RSVA - Power	1588	$ 241,897	$ 32,443					$ 274,340	$ (6,182)	$ 17,476		$ 11,294
Sub-Totals		$ (1,031,121)	$ (278,793)	$ -	$ -	$ -	$ -	$ (1,309,914)	$ (84,615)	$ (37,649)	$ -	$ (122,264)
			$ -									
Other Regulatory Assets - Sub-Account - OEB Cost Assessmer	1508	$ 29,807	$ -	$ -	$ -	$ -	$ -	$ 29,807	$ 3,739	$ 951		$ 4,689
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 67,724	$ -	$ -	$ -	$ -	$ -	$ 67,724	$ 8,508	$ 3,202		$ 11,710
Retail Cost Variance Account - Retail	1518	$ (5,666)	$ (7,247)	$ -	$ -	$ -	$ -	$ (12,913)	$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ (1,819)	$ (582)	$ -	$ -	$ -	$ -	$ (2,401)	$ -	$ -		$ -
Misc. Deferred Debits	1525	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
LV Variance Account	1550	$ 76,291	$ 22,570	$ -	$ -	$ -	$ -	$ 98,861	$ 4,052	$ 3,574		$ 7,626
Smart Meter Capital and Recovery Offset Variance - Sub-Accou	1555	$ (39,381)	$ (18,865)	$ -	$ -	$ -	$ -	$ (58,247)	$ (1,917)	$ (2,031)		$ (3,948)
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Conservation and Demand Management Expenditures and Rec	1565	$ (15,068)	$ 15,068	$ -	$ -	$ -	$ -	$ 0	$ -	$ -		$ -
CDM Contra	1566	$ 15,068	$ (15,068)	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -		$ -
Qualifying Transition Costs [5]	1570	$ (10,879)	n/a	n/a	$ -	$ -	$ -	$ (10,879)	$ (867)	$ (514)		$ (1,382)
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Regulatory Asset Recovery	1590	$ (74,142)	$ 138,584	$ -	$ -	$ -	$ -	$ 64,442	$ (49,425)	$ 1,029		$ (48,396)
Sub-Totals		$ 41,934	$ 134,460	$ -	$ -	$ -	$ -	$ 176,394	$ (35,911)	$ 6,210	$ -	$ (29,701)
Total		$ (989,186)	$ (144,334)	$ -	$ -	$ -	$ -	$ (1,133,520)	$ (120,527)	$ (31,439)	$ -	$ (151,966)
								$ (1,133,520)				$ (151,966)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 17,102	$ 80,668					$ 97,771	$ -	$ -		$ -

Orangeville Hydro Limited Plan to Enable the Green Energy Act

2009

The purpose of this enabler plan is to identify Orangeville Hydro's proposed plan of implementation for aspects of the Green Energy Act that would apply to Orangeville Hydro Limited and its customers. Orangeville Hydro is seeking general approval from the Ontario Energy Board to carry out its plan.

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LIST OF ACRONYMS

AMI	Advanced Metering Infrastructure
CDM	Conservation and Demand Management
CHEC	Cornerstone Hydro Electric Concepts
CMI	Count Me In
DG	Distributed Generation
DR	Demand Response
ERIP	Electricity Retrofit Incentive Program
FIT	Feed-in Tariffs
GAM	Global Adjustment Mechanism
GEA	Green Energy Act
GHG	Green House Gas
GIS	Global Information System
LDC	Local Distribution Company
OEB	Ontario Energy Board
OHL	Orangeville Hydro Limited
OPA	Ontario Power Authority
PS	Peak Saver
PSB	Power Savings Blitz
PURE	Power Up Renewable Energy
RC	Renewable Connection
RESOP	Renewable Energy Standard Offer Program
ROI	Return on Investment
SCADA	Supervisory Control and Data Acquisition
SG	Smart Grid
SM	Smart Meter
TGRR	The Great Refrigeration Round Up
TOU	Time-of-Use

EXECUTIVE SUMMARY

The purpose of this Green Energy Act (GEA) enabler plan for Orangeville Hydro (OHL) is to:

1. Identify OHL's proposed activities to implement aspects of the GEA applicable to OHL Limited and its customers; and,
2. Seek approval and funding from the Ontario Energy Board (OEB) to carry out the activities set forth in this document to implement the proposed plan;

The next steps will result in the creation of documents that will:

1. Provide the positions available to OHL;
2. Frame the choices available to OHL that will require Board of Directors approval;
3. Document the elements that will be required to gain approval from the OEB, specially accounting orders; and;
4. Assist in developing the Business Case for 'green' jobs primarily in Orangeville and Grand Valley.

To position OHL as a leader in GEA compliance, an ambitious set of strategic goals are being proposed. The timeline for proposed implementation of the goals is based on activities that take place during two timeframes; Years 1-5 and Years 6-11. While this plan begins January 1, 2010, it is based on underlying assumptions about GEA framework, and it reserves the right for the relative timing and value of the projects to be revisited as regulations and directives are issued or become available.

Based on strategic fit, constraints, risk and reward considerations, an ambitious list of goals under the GEA has been developed. There is a unique set of activity requirements that must be carried out to achieve each respective goal. OHL has a high degree of knowledge for the 6 short term strategic goals and the activities required to achieve them are generally known. High priority strategic goals include:

1. Commissioning of the Smart Grid through the large-scale, yet prudent investment in T&D infrastructure aimed at enabling, and improving, advanced metering, Demand Response, asset management, and system reliability;
2. Installing and connecting Distribution Generation systems to residential and commercial customers;
3. Continuing to support and enhance OEB, Ministry, and Ontario Power Authority (OPA) Conservation and Demand Management objectives. In particular, we will evolve Conservation Demand Management (CDM) opportunities by promoting Demand Response initiatives to residential customers through OPA and custom programs;
4. Promoting, educating and packaging renewable energy resource based solutions through our affiliate Green Pathways Inc. and become the "One-Stop-Energy-Shop". A marketing campaign will be used to engage and inform the various market segments throughout Orangeville and Grand Valley;
5. Launching programs that will support the installation and operation by residential and small business customers of (less than 10 kW) green electrical power generating systems on their properties; and,
6. Installing and operating a large renewable system within the 10MW limit at OHL's corporate office. This installation will also serve as a technology demonstration site, particularly of Ontario and Canadian renewable electricity generation technology;

The lower priority strategic goals are long term visions that OHL will investigate. These include:

- Cap and Trade;
- Combined Heat and Power;
- Waste Energy;
- Electric Vehicles; and,
- Generation Activities.

This Enabler Plan includes the proposed activity, benefits of the activity, timeframe for activity, risk assessment and estimated cost. Benefits of various projects are grouped to realize cross-functional gains.

During the Period of Performance of this proposed plan, it is estimated that 11.5 jobs will be created, 7 of which will be skilled, full-time and long-term positions. The goal is to create “green collar” jobs in the design, manufacturing, installation, CDM, service and education sectors.

The investment/cost of executing this proposed plan in its entirety is conservatively estimated at $3.04 million over 5 years, with an annual average expenditure of $303,344.56 (Capital ($334,800) + Expenses ($271,889.12). The first three years will require $1.91 million (Capital ($1.07 million) + Expenses ($840,000). Partially offsetting these capital expenditures will be the cost avoidance associated with the reduction in electricity demand through our CDM programs.

1 OVERVIEW

1.1 THE GREEN ENERGY ACT

On February 2009, Minister Smitherman announced Bill 150, Green Energy and Green Economy Act, 2009. The GEA has now received Royal Assent. The vision of the GEA is “to make Ontario a global leader in the development of renewable energy, clean distributed energy and conservation, creating thousands of jobs, economic prosperity, energy security, and climate protection”. The Ministry plans on achieving its vision by “facilitating the development of a sustainable energy economy that protects the environment while streamlining the approvals process, mitigates climate change, engages communities and builds a world-class green industry sector” (Minister Smitherman, 2009). The Act addresses all forms of ‘green’ power production and conservation of all forms of energy and is designed to address opportunities in all three areas of the energy supply chain.

Figure 1 - Opportunities in Energy Supply Chain

The GEA delivers a Climate Change Strategy, positioning Ontario as a world-leader in clean technology. The GEA is intended to foster the growth of renewable energy projects, remove barriers to and promote opportunities for renewable energy projects and to promote a green economy and thereby create a significant number of well paying, long term jobs.

The Act also encourages everybody, whether homeowners, businesses or institutions, to engage in and practice energy conservation and use energy in an efficient manner. Both industry and public support is strong, creating optimism for local economies. Municipalities and utilities are investigating ways to expand core lines of business to take advantage of opportunities created by the Act.

SMART GRID

The Smart Grid enables a two way flow of data and information in the electricity system. The Smart Grid uses “sensors, monitoring, communications, automation and computers to improve flexibility, security, reliability, efficiency, and safety of electrical system” (Ontario Smart Grid Forum, February 2009). The benefits of the Smart Grid are as follows:

- Enhanced reliability of distribution system;
- Reduced outages;
- Quicker response times;
- Better integration of renewables and Distributed Generation (DG);
- Grid optimization;
- Electric vehicle support;
- More efficient use of energy infrastructure; and
- Allows consumers to make consumption choices (I.e. Demand Response).

Smart Meters automatically record when electricity is used and make Time-of-use (TOU) rates possible. TOU pricing through Smart Meters, provides Demand Response, price information, and load control to electricity consumers.

CONSERVATION AND DEMAND MANAGEMENT

Conservation and Demand Management (CDM) has been given a higher profile in the Ministry of Energy. Within the context of the GEA, CDM is defined in terms of the following:

- **Conservation Behaviour** – changing habits or processes to reduce energy consumption;
- **Energy Efficiency** – gain from using more efficient appliance and equipment;
- **Demand Management** – occurs when customers reduce their electricity demand during peak hours (load shifting);
- **Fuel Switching** – customers elect to use other energy sources in place of electricity; and,
- **Distributed Generation** – generates electricity from many small energy sources.

RENEWABLES

The GEA also facilitates the installation of relatively small scale renewable energy based electricity generators that can be grid-tied. The Ministry has shown strong support for renewable energy policy initiatives under the GEA, some of which include:

- Enhancing commitment to renewables ;
- Enabling Feed-in Tariffs (FIT) to procure renewables ;
- Guaranteeing and prioritizing connection of renewables; and,
- Streamlining approvals.

1.2 SITUATIONAL ANALYSIS

A SWOT analysis was developed at a Strategic Planning session held with the Board of Directors in December 2008. The SWOT analysis excludes implications under the GEA and its purpose is to provide insights into the general pulse of the organization.

STRENGTHS

The following were identified as strengths of the organization:

- Strong management team (for size of the organization);
- Productive labour force, and supportive union (local membership);
- Foresight to establish Green Pathways Inc. as a One-Stop-Energy-Shop which provides high level of service and customer satisfaction, based on survey results; and,
- Good relationship with Town, including Town CAO, Home Builders Association, Dufferin Manufacturing Association and Chamber of Commerce.

PROACTIVE RESPONSES TO PERCEIVED WEAKNESSES

The following were identified as weaknesses of the organization:

- Limited land for development – bound by Hydro One
  - Grow business through green opportunities;
- Aging labour force – 5 year retirement window
  - Succession plan is in place;
- Risk averse Shareholder
  - Build business cases that provide shareholder comfort with acceptable risk;
- No formal asset management strategy
  - Formalized asset management strategy is being completed with assistance from Hatch Engineering; and,
- Organization populated with generalist, few opportunities to specialize;
  - Access to specialized resources through organizations such as Cornerstone Hydro Electric Concepts (CHEC), Green Pathways Inc., Power Up Renewable Energy (PURE), Rodan Energy and Metering Services.

OPPORTUNITIES

The following were identified as opportunities for the organization:

- Leverage CHEC membership
  - Cost savings and resource sharing;
- Green Pathways Inc.
  - Broader scope of business opportunities;
- Operation integration of Grand Valley
  - Expanded customer base allows for greater cost effectiveness; and,
- Rate design
  - Creating a model for better rate allocation.

THREATS

The following were identified as threats to the organization:

- **Government Policies** – risk and uncertainty increasing, as changes in role of regulator and increased expectation from individual LDCs; and,
- **Regulatory risk** – rate rebasing is more than a financial exercise, it is the foundation for future revenue – expectations and requirements continue to change.

1.3 ENVIRONMENTAL ANALYSIS

OHL is a municipally owned Local Distribution Utility, servicing the town of Orangeville and the former Village of Grand Valley. The LDC services almost 11,000 customers and has a strong, highly skilled management team, many of whom are long serving employees with the utility. With over 90 years of supplying the region, OHL has an intimate knowledge of the utility and its operations.

The Town of Orangeville and the Township of East Luther Grand Valley have been identified by the province as places of growth. This means that unless Conservation and Renewable Generation activities are proactively pursued, the ability to service the anticipated growth will be compromised. OHL expects a minimum of 9% growth in customer numbers overall. Normally, this would relate to an approximate increase of 14% in demand when commercial and industry customers are taken into account. However, due to economic conditions, Orangeville has lost a couple of industries with another major industry to close down soon. We are therefore forecasting our demand to decrease in comparison to 2009 demand. The proposed conservation programs will further improve our demand. OHL together with its affiliate, Green Pathways Inc., chooses to be responsive rather than reactive to the evolving energy environment.

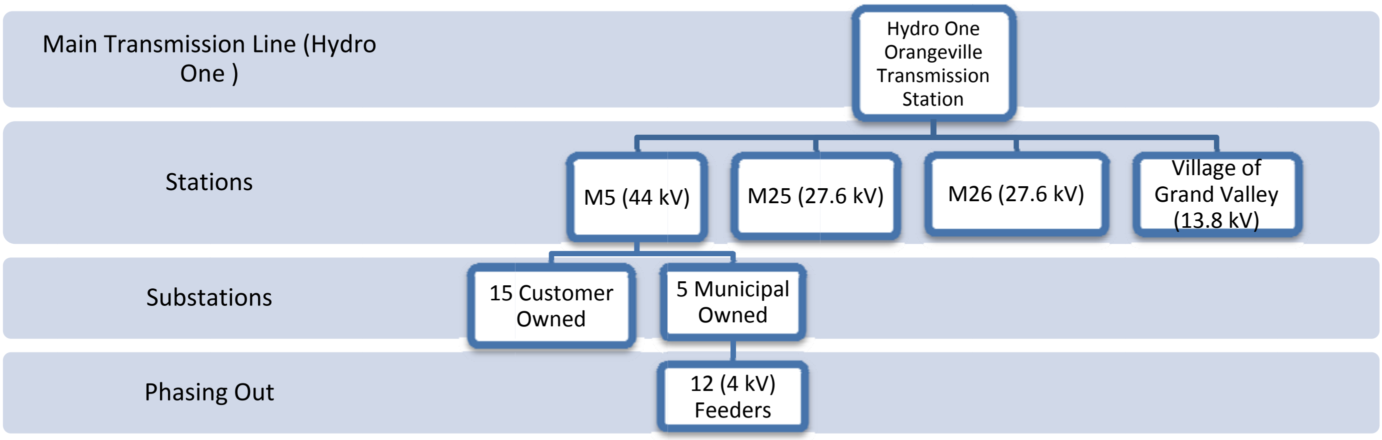
OHL has 3 feeders which are fed from the Hydro One Orangeville Transmission Station.

The M5 is a 44kV feeder which feeds 5 municipal substations and 15 customer owned substations. An older 4kV system of 12 feeders is then fed from the 5 municipal substations. OHL has been gradually, over the past 20 years, converting load from the older 4kV system to a newer standardized 27.6kV system. There are 2 - 27.6kV feeders, the M25 & the M26.

OHL also looks after the Village of Grand Valley. There is only one 13.8kV feeder which is fed from a Hydro One Distribution Station.

Both Orangeville and Grand Valley are fed from the same Hydro One transmission station. The allowable distributed generation that Hydro One has set for this station is 53.1 MW on the 27.6kV portion and 34 MW on the 44kV portion.

Figure 2 - Feeder Infrastructure



In going forward with any new set of initiatives, it is prudent to have a common understanding of the environment in which you are operating. The political, economic, social, and technological implications of the GEA on OHL are included below.

POLITICAL

- OHL believes that the greatest single risk is linked to uncertainty of regulatory and political climate; and,
- As a provincially regulated entity, changing requirements create risk to the company, which is directly linked to risk to the town in both rates (customers) and dividends (municipality).

ECONOMIC

- Ontario's economy stalled in 2008 and is likely to see nothing more than slow growth in 2009;
- Although the current economic climate will have implications for OHL, its customers and the local community – many participants of the strategic planning session feel it will be no greater than the impact felt by other similar industry players and mostly beyond the control of OHL;
- The recession may limit the number and type of opportunities, creating a shorter time horizon than other similar plans; and,
- It should be recognized that during the implementation of this Plan, a number of significant events and activities will occur that will affect the supply and demand of electricity power and thus will influence its execution.

SOCIAL

- Relates largely to ratepayers and taxpayers, and their perceptions of what is happening in their local community;
- Perceptions could be affected by future rate increases brought about by factors beyond the company's control (Global Rate Adjustment); and,
- OHL's customer base is anticipated by 2020 to grow to 13,000 residential and commercial customers.

TECHNOLOGICAL

- Generally concerned with emerging trends in the use of the new green technologies by either the company or its customers – the impact of Smart Meters needs to be considered and could be seen as a structural change in the energy industry.

1.4 COMPANY STRATEGY

The strategic goals OHL is proposing to enable the GEA must be aligned with the company's overall strategy. The top four priorities for OHL (in no particular order) include:

- Growing the business to benefit the community and through green business opportunities;
- Leveraging the benefits of CHEC membership – Continue to encourage CHEC to lobby to reduce response requirements by the regulatory entities;
- Possible mergers to grow the company. It is of paramount importance to OHL that they be the majority shareholder – investigating growth with same size or smaller businesses ; and,
- Investigating opportunities to utilize renewable energy, and pursue potential partnerships with renewable energy companies.

Other notable strategies include:

- We will stay current with industry, sector, and regulatory changes;
- We will continue to comply with all legislation related to our industry, as well as all other government regulations that are required of us;
- We will investigate areas that are within our control to reduce or curtail costs, or to better utilize resources;
- We will develop a formal asset management plan to enhance the overall value of the organization;
- We will network with other boards to develop and share best practices; and,
- We will keep the board informed but our main focus will be on the customer's needs.

1.5 RECENT COMPANY SUCCESSES

ORANGEGILLE HYDRO

- **Peak Buster Award, October 2008 -** OHL is one of seven Ontario electric utilities that have won a Peak Buster Award for keeping the summer peak power demands below the provincial average;

- **Ontario Clean Air Alliance Award, 2007 -** OHL received one of eight "Peak Buster" awards for reducing peak electricity demand this past summer below the provincial average. OHL collaborated with Orangeville Sustainability Committee to Create the Orangeville Energy Calculator which calculated averages of OHL usage to be used for comparative purposes against the average Orangeville home;

- **Reduce the Juice** – Promoted conservation programs on behalf of the Ontario Power Authority through direct interaction with our community by way of door-to-door canvassing, participation in the Farmers Market and Founders Fair. Reduce the Juice worked in conjunction with local businesses offering energy audits and discounted energy retrofits to help promote energy conservation;

- **Green Pathways Inc. has run 2 programs; Power Savings Blitz (PSB) and Electricity Retrofit Incentive Program (ERIP)** – Green Pathways Inc. has been a delivery agent in 2008 & 2009, promoting the PSB and ERIP program on behalf of OHL;

- **Network** – OHL has worked with various organizations such as Reduce the Juice, PURE, Green Pathways Inc. and other LDCs through its CHEC affiliation to help develop a culture of conservation within the community; and,

- **Home Shows** – OHL showcased the Hazard Hamlet for kids that helped explain the dangers of live electricity. OHL also promoted OPA programs within the community.

GREEN PATHWAYS INC.

Green Pathways Inc. was established in May 2008, in partnership with the non-profit group PURE. Although relatively new, this One-Stop-Energy-Shop is gaining tremendous credibility in the community by virtue of its efforts and customer responsiveness. OHL has had excellent success working in conjunction with Green Pathways Inc., in delivering various sets of programs. The demonstrated passion and desire to find total solutions of Green Pathways Inc. strongly positions it to execute and further the proposed GEA activities, in conjunction with OHL, as they relate to CDM and Renewable Energy Generation.

While the current demand for electricity has diminished due to the economic down turn, this plan recognizes the need to consider long-term planning because of the ultimate state of generation in the province (decommissioning of coal fired generators and nuclear life expectancy). Green Pathways Inc. will continue to support its initiative to be known as the One-Stop-Energy-Shop in the Orangeville area and beyond.

2 VISION

OHL, together with its affiliate service company Green Pathways Inc., aspires to establish itself in the minds and actions of its customers as the preferred source of unbiased, credible and authentic information for CDM and Renewable Generation. OHL aspires to be recognized as the source of reliable and excellent quality Small-Scale Renewable energy based equipment together with its installation in all aspects – a competent, dependable facilitator and total solutions provider. OHL's vision under the GEA for Smart Grid, CDM, and Renewable Generation is set out below.

SMART TECHNOLOGY

- To build a Smart Grid that will meet the technical needs of our customers and is economically prudent; and,
- Exercise vigilance with respect to the size and makeup of the OHL's Smart Grid as smart meter functionality increases.

CONSERVATION

- To reduce its per capita consumption by a minimum of 7% in the next five years (based on 2009 consumption); and,
- To use aggressive conservation practices to cap the increase in demand, caused by customer growth at 5 MW in 2020 - the forecasted demand is 6MW, based upon current usage and generation.

RENEWABLE GENERATION

- To install renewable energy based generation capability to service its Orangeville and Grand Valley customers – connecting 800 premises with small scale renewable energy based generation capabilities with a total capacity of 2,400 kWs.

COMPLIMENTARY VISIONS

In addition to government mandated/driven initiates, OHL also has the vision to:

- Deliver, educate, and provide training in programs that will in partnership with Green Pathways Inc. meet the needs of OHL's customers; residential, low income, seniors and commercial;
- Establish Green Pathways Inc. as a recognized and integral part of the delivery of services and products associated with OHL's enabling of the Green Energy Act;
- Implement facilities to support servicing electric vehicles with emphasis on converting the Town's buses to electric; and,
- Create 7 long-term sustainable "green collar jobs" within OHL.

3 PROPOSED STRATEGY

3.1 ASSUMPTIONS AND CONSTRAINTS

The strategic goals proposed in this plan are premised on assumptions and supporting facts including but not limited to:

- LDCs will be allowed to invest in Renewable Generation assets under the GEA legislation;
- Any investment inside the LDC will be considered a utility asset and eligible for Regulated Rate of Return (Generation Adjustment Mechanism (GAM) or distribution rates for customers);
- A significant number of Small-Scale Renewable energy based Distributed Generation projects will make a positive contribution to lower electricity deliveries by OHL;
- OHL will partner with private sector and 3rd party delivery channels to gain expertise in areas that are not currently core strengths;
- The replacement/refurbishment of much of the province's existing generating capability will be well underway (Note: all coal-fired generators decommissioned by 2012);
- All customers using Smart Meters will be subjected to Time-of-Use (TOU) billing;
- The "conservation culture" being promoted under the CDM plans will encourage customers to reduce electricity consumption;
- OHL will continue its voltage conversion program as opposed to modifying the five existing municipal substations (estimated cost: 1 million dollars per station);
- There are areas of the province where the transmission system has limited or no ability to accept new generation. OPA will be prudent and not procure new generation that will exceed the capacity limit (based on approved or allocated projects); and,
- Hydro One will develop a transmission plan that outlines system upgrades and reinforcements to overcome some known constraints.

3.2 PRIORITIZATION CRITERIA FOR STRATEGIC GOALS

It is the overarching goal of OHL to fully embrace and comply with the Green Energy Act, to the best of our ability, in an economically prudent manner. This will protect our customers and our shareholders.

The strategic goals with respect to the GEA are consistent with the strengths of the organization. Our objectives are to be a promoter and installer of renewable energy devices and equipment and an effective deliverer of a comprehensive selection of conservation programs. In addition to complying with legislation and orders of the regulatory, OHL will achieve its strategic goals by setting realistic and feasible short goals as well as a long term vision. The strategic goals are consistent with OHL's vision and are directed by the core strengths within the organization.

The proposed timelines are based on underlying assumptions about GEA framework. As regulations and directives become known, relative timing and value of projects will need to be revisited. OHL is seeking clarification of approval requirements to ensure cost recovery. OHL recognizes change continues to occur (regulatory oversight) and that re-assessments will be required.

SHORT- TERM (YEAR 1-5)

The short-term strategic goals are provided in Part 3 of this document and are Goals 1-6. They are of high priority and their achievement commences at the start of Year 1 (January 1, 2010). OHL has already begun the planning and implementation phases for these. An estimate of the capital and operating costs associated with implementing the short-term goals are shown in Table 3 in section 5.

However, some of the proposed activities under the short-term goals will require additional time to plan and implement due to the regulatory, operational, and the technological nature of the activities (I.e. some of the business cases have not been completed, capital and operating costs and respective return on investment are unknown).

LONG TERM 6-11 YEAR GOALS

The long-term strategic goals are the proposed objectives to be achieved during the 6-11 year period. Achieving these goals, are dependent on feasibility studies or business cases that will be completed at a later date or as opportunities arise. These goals provide long term direction for OHL.

3.3 SHORT TERM STRATEGIC GOALS (YEARS 1-5)

GOAL 1: DEVELOP SMART GRID INFRASTRUCTURE AND INSTALLATION OF SMART METERS

SITUATION

The provincial mandate for installing Smart Meters and implementing an advanced metering infrastructure is considered the first step in realizing the Smart Grid. OHL's current system requires upgrading to improve its performance and efficiency and to deploy a Smart Grid to the benefit of its customers.

Presently, OHL does not have a SCADA system because the benefits did not warrant the cost. In order to implement a Smart Grid, OHL will need to install SCADA (i.e. by sharing costs with other CHEC group members). OHL has had preliminary discussions with a neighbouring LDC regarding the costs of sharing a SCADA system.

STRATEGY

OHL recognizes that there are many functionalities of the Smart Grid as previously identified in section 1.1. As a first step, OHL would like to allow TOU billing to enable Demand Response and Load Control during critical peak periods to immediately assist the customers in a more efficient use of their energy.

The next steps in this progression will be advancement of metering technologies and the integration of functionalities to realize new enabled services. OHL plan is to make investments with respect to Advanced Metering Infrastructure (AMI) include:

- Retrofits or add-on equipment of first generation meters in strategic areas; and,
- Expansion and leverage of the advanced metering infrastructure – data analytics, outage reporting, theft detection, remote disconnects, power quality monitoring, spot price settlement for generation, etc.

In order to optimize the implementation of the Smart Grid, OHL will continue to convert older 4kV feeders to the newer standardized 27.6kV distribution system over time through our normal capital works program. However, the equipment necessary to make the grid smart has not been included in our normal capital works. In addition, there are a number of components of our distribution system that have been converted and will require upgrades to make them 'Smart', including:

- Installation of Remote Sensing and SCADA;
- Motorized Switches;
- Engineering Design; and
- PME Upgrades.

SUCCESS INDICATORS AND TARGETS

- Enhanced reliability of the electricity system;
- New Distribution Generation facilities attached to grid and enhanced efficiency of distributed network;
- Job creation; and,
- A fully integrated Smart Grid capable of facilitating all forms of generation, and reduction in energy consumption per capita, based on 2009.

FINANCIAL IMPLICATIONS

Implementing Smart Grid infrastructure is a long-term investment. OHL will make prudent decisions taking into account the needs of its customers and capital providers (i.e. shareholders). It recognizes that the objective will have a very significant financial impact on the organization.

Rather than modifying the five existing 4kV municipal substations at an estimated cost of 1 million dollars each, OHL will continue its voltage conversion program – not a financial implication, rather a cost minimization decision.

The implementation of a fully functional Smart Grid would also create 1 new full-time job, with an annual salary of $80,000 per year plus benefits ($100,000 total in 2009 dollars).

To enable the Demand Response and Load Control, it is estimated that the in-home information system would cost approximately $420 per customer and will utilize the Smart Meter infrastructure.

GOAL 2: DISTRIBUTION UPGRADES TO ENABLE DISTRIBUTED GENERATION AND FIT PRICING

SITUATION

Under the GEA, the connection of Renewable Generation requires priority access to the electricity grid, as well as an obligation by utilities to connect such generation into their system.

OHL will prepare a streamlined process to connect Renewable Generation. This will include financing, installing, maintaining, and billing for small Renewable Generation installations. Capital and operating costs in the area of renewable energy generation connection administration include:

- Contract administration;
- Customer service;
- Billing and Settlement – include an automated process for settlement between LDC interval meter data with IESO spot price;
- CIS upgrades;
- Promotion/communication;
- Connection Contracts;
- Standardized contracts, financial/legal/commercial involvement; and,
- Online self-assessment portal, including tracking application and project status.

OHL is committed to cooperating fully with commercial generators to give Orangeville a competitive advantage over other locations. To facilitate a streamlined connection amongst utilities, standards development in the areas of engineering, communication and operation is required. The plans for standards development include:

- Development of additional standards;
- Convergence of standards as appropriate;
- Pre-qualified contractors; and,
- Safety standards.

Metering is an essential component in the facilitation of renewable energy connection. This includes:

- Meter base/meter technology;
- ESA requirements for meter locations – minimize meter relocations; and,
- Leveraging the advanced metering infrastructure for check metering and verification of generation source.

The amount of generation capacity from distributed generation allowed to be fed back into the grid is constrained by a variety of engineering factors, such as short circuit capacity, ampacity, power quality, and protection and control. It is anticipated that in the initial rollout, the connection of inverter-based Renewable Generation will not impose many limitations, though larger scale synchronous generation will be more constrained.

Additional investments required to enable Distributed Generation include:

- Studies to determine existing capacity to accommodate Renewable Generation of various types and methods/actions required to eliminate constraints;
- Determination and publication of guidelines to be used for initial planning purposes for sizing generation capacity within the distribution system (i.e. by voltage, station, feeder or geographical location);
- Description of plans to mitigate constraints on an as needed basis, to the maximum extent technically possible;
- Coordination amongst distributors and transmitter, to remove regulatory barriers to expand infrastructure in supporting Distributed Generation; and,
- Appropriate protection of confidential or commercially sensitive information.

OHL's new Distribution Generating capacity will enhance and expand on its current capacity (shown in Table 1, below).

Table 1 - Current Generating Capacity

	Voltage	2008 Peak	2008 Low Pt.
M5	44 kV Delta	18.6 MW	11.7 MW
M25	27.6 kV Wye	10.7 MW	4.4 MW
M26	27.6 kV Wye	11.1 MW	4.8 MW
Grand Valley	13.8 kV Wye	2.2 MW	0.9 MW

ASSET MANAGEMENT PLAN

OHL is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. OHL distribution assets range in age from new to over 60 years old.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of OHL's physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates. OHL does not have a formal asset management plan. For this first stage in developing an asset management plan, we contracted Hatch and Associates to assist by doing a comprehensive review and analysis of current asset condition. Accompanying this proposal in the Rate Application as Appendix A is a September 8, 2009 document titled "Asset Management Executive Summary Report". The findings of the Asset Management Condition Assessment Report will be used as a guideline to determine the short-term capital expenditure levels until there is more work completed on the data and asset management strategies contained within an Asset Management Plan. This report contains analysis of overall asset condition and assisted OHL in determining our 2010 and 2011 capital expenditures. It is important to note that OHL's formal Asset Management Plan is in its early development stage and in 2010 we will implement a GIS system and will perform a system optimization study. OHL will use the results of our future study along with the recent condition assessment to help us effectively plan capital and maintenance sustainment work programs.

There is no requirement for a short-term strategy to replace meters as the Smart Meter Initiative will likely result in the replacement all of OHL's meter assets in the next few years.

The plan for Substation assets is currently under investigation by OHL to determine its context with respect to the strategy for the conversion of distribution system overhead and underground 4.16 kV line assets to 27.6 kV thus allowing for a further reduction of the four remaining municipal substations.

STRATEGY

Our strategy is to complete all the necessary distribution upgrades required to enable Renewable Generation connection to the grid. Non –Renewable Generators must still be connected to the distribution grid and will be connected to the grid in a similar fashion as the renewable generators.

GOAL 3: EVOLUTION OF CDM

SITUATION

OHL delivers electricity conservation and energy efficiency programs to both commercial and residential consumers through programs offered by the Ontario Power Authority (i.e. Every Kilowatt Counts). OHL will continue to support these programs, and will develop customized programs to create a culture of conservation - to encourage reduction of consumption while building awareness within its communities.

Since the establishment of the Conservation Bureau, within the Ontario Power Authority, as included in the Electricity Act, 1998, there have been a number of primary electricity conservation programs undertaken, both as community initiatives and as programs offered by the Ontario Power Authority. “Every Kilowatt Counts” is a branded initiative that encompasses all of the OPA programs: Its objective is to focus the consumer on one theme when they think of energy conservation. Under this program, OHL has gained experience delivering both community initiatives and individual programs. An example of the former is the highly successful “Reduce the Juice” program. This program involved having a team of trained high school students, under the supervision and oversight of professional staff, go door-to-door in both residential and commercial sectors, obtaining pledges of electricity reduction, and, offering a selection of more energy efficient light bulbs for purchase by the premises owner/occupier. This resulted in a minimum of a 5% reduction in electricity consumption.

Examples of the latter are the Power Savings Blitz-Direct Install program and the Electricity Retrofit Incentive Program. Both these programs have recently been awarded to Green Pathways Inc. who will act as Delivery Agent, and both these programs are on-going.

However, the Green Energy Act proposes the dissolution of the Conservation Bureau and vests the execution of energy conservation programs in the Ontario Energy Board. This would be an opportune time for OHL, in collaboration with Green Pathways Inc., to review the various electricity conservation programs for effectiveness. Subsequent to this review, initiatives, programs and projects considered to be most effective and consistent with our electricity conservation and demand reduction goals, will be proposed. During this review period the existing programs would continue to be offered.

STRATEGY

OHL will continue to support and enhance OEB, Ministry, and OPA objectives and ensure access to province wide programs and work with retailers, businesses, and associations to help promote this agenda.

With respect to OPA Programs, OHL plans to explore opportunities for promoting Demand Response initiatives involving all OHL customers. The Demand Response programs that OHL will explore include:

- **DR 1**- Encourage short term Demand Response capacity in response to the IESO Three-Hour Ahead Pre-Dispatch signal in the electricity market;
- **DR 2** - Participants can contract to reduce a pre-determined amount of load for a minimum period of four consecutive hours up to a maximum of 12 consecutive hours; and,
- **DR 3** - Participants make themselves available during scheduled hours for potential notices to reduce load.

OHL will also explore the commercial applications through OPA incentive based programs to help reduce peak demand for electricity in the Orangeville area and the burden on currently constrained areas. In rolling out existing OPA programs, funding should be available through OPA; however some additional local promotion and customer incentives will be required.

With respect to Utility-specific Programs, OHL proposes to enhance the overall customer base by acknowledging that a great deal has already been accomplished through Demand Management; however existing programs may not be enough to reach provincially allocated targets.

Any new programs will require additional funding and may not initially be cost effective according to existing metrics.

GOAL 4: MARKETING CAMPAIGN

SITUATION

The Green Energy Act states: “The Government is committed to fostering the growth of renewable energy projects….and to removing the barriers to and promoting, the opportunities for renewable energy projects and to promoting a green economy.”

It has been determined that there is a significant lack of knowledge in the consumer community with regard to the various aspects addressed by the Green Energy Act. OHL, in collaboration with Green Pathways Inc. and qualified experts, intends to address this situation by developing consistent vehicles of communication upon which our communities can rely upon to obtain current information regarding all aspects of conservation and renewable energy.

STRATEGY

To accomplish our proposed goals in response to the GEA, OHL in partnership with Green Pathways Inc., recommends introducing customized programs to foster a “grassroots” customer understanding of CDM. We will lean heavily on education and awareness activities. In the execution of our education and awareness plan, we will work together with our subsidiary Green Pathways Inc.. The marketing plan will commence January 1, 2010. The first 6 months will be used to assess current activities and properly construct the Marketing Plan. Our strategy is to educate and encourage the following market segments:

- **Business/Industry Institutions and Associations:** OHL and Green Pathways Inc. will continue to capitalize on their excellent relationships with The Greater Dufferin Area Chamber of Commerce, The Dufferin Area Manufacturers Association, The Business Improvement Association, The Dufferin Builders Association, The Headwaters Tourism Association, and the Dufferin Farmers Association. We will foster relationships with any company or association that furthers our CDM agenda. Our current activities include ERIP and PSB participation. Past activities include participation in the Eco Energy, Home & Lifestyle show, and Reduce the Juice. The main goal is to:
    - Introduce energy conservation information, programs and products on CDM and renewables to all new and existing commercial businesses.
- **Schools and Educational Facilities:** Educating students may be our best channel for communicating awareness and inspiring further reaching activity. Any proposed programs will encompass all children from JK-G12. Within the timeframe of our short and long term goals, many students will graduate, join the work force, and become home-owners/renters. The goals are to:
    - Work with schools boards and schools through the Grade 5 pilot project, to educate students on consumption, the environment and green energy so they can contribute to the realization of the long term goals and objectives of the GEA, with respect to CDM and the introduction of renewables;
    - Complete our proposed 6 month assessment which will include:
        - Assessing viability of holding a local “Green Science Fair & Expo” (If successful, it may be expanded to Regional or Provincial levels).

- **Residential Homeowners:** This is a diverse age group of varying socio-economic circumstances and levels of education. OHL and Green Pathways Inc. will extensively educate this segment with regards to Smart Metering, CDM, and Renewables. Our current activities include The Great Refrigerator Round Up (TGRR) and Peak Saver (PS) participation. Past activities include participation in the Eco Energy, Home & Lifestyle show, and Reduce the Juice. Our goals are to:
    - Introduce energy conservation products and information on CDM and renewables to all new and existing residents within Orangeville and Grand Valley with our Welcome Wagon Program;
    - Conduct a feasibility study to consider residential programs modeled after ERIP and PSB; and,
    - Determine financial viability during the 6 month prior to implementation of proposed activities,
- **Low Income & Seniors:** This is an excellent channel to promote awareness/education since they are a diverse age group of varying socio-economic circumstances and levels of education with a similar goal or focus to cut costs
    - Introduce energy conservation products and information on CDM and renewables to all new and existing low income residents within Orangeville and Grand Valley with our Welcome Wagon Program;
    - Implement residential programs modeled after ERIP and PSB; and,
    - Address the needs of our community for those who are on a fixed income, who cannot afford to purchase energy saving products;

PROPOSED RESOURCES

Engagement and information delivery techniques and practices will be those that are found to be the most effective for the particular group. The following actions are suitable for enhancing awareness:

- It is proposed that OHL's current facility become a technology and practices 'flagship' and be a demonstration site for Ontario and Canadian green technology;
- Develop a strong information and responsive website for OHL, with an emphasis on conservation, renewables, energy efficiencies, incentives and links to programs, suppliers, governments and agencies, including assessment tools;
- Create a common vehicle for communicating energy saving programs and news to the community through an online newsletter and "Community Conservation Lending Library" within Green Pathways Inc. office. It is our view that Green Pathways Inc. will develop an extensive resource library specific to the green world, including renewables, conservation and energy efficiency;
- OHL in conjunction with Green Pathways Inc. will provide information sessions and workshop seminars to the various segments of our communities;
- Explore the viability of a 'high impact' alternative-fueled green vehicle to serve as a mobile display and demonstrator. All systems and furnishings within this vehicle would be examples of green technology, and could be utilized for both education and training.

Programs and Technical Training: As this Plan is executed there will be a demonstrable need for both program training and technical training. These methods will act as a consistent vehicle for our community and staff to rely on regardless of the program being implemented.

GOAL 5: SMALL-SCALE RENEWABLE RESOURCE GENERATION INSTALLATIONS

SITUATION

The GEA encourages and facilitates small scale distributed generation installations. These will be executed under the auspices of the MicroFIT Program.

OHL wishes to take full advantage of this opportunity and views small-scale renewable generation /distributed generation as residential and small business owned wind and solar projects. Other technologies may also be included.

STRATEGIES

OHL envisions being the 'one-stop-energy-shop' for all of our customers as well as residents in the rural area surrounding Orangeville and Grand Valley. OHL would like for customers to be able to purchase their systems from, have them installed and maintained by, financed through, and billed by OHL.

Since this is not currently allowed by our license, we anticipate initially conducting these activities through our affiliate Green Pathways Inc. (Note: this arrangement may prove to be the most efficient and effective vehicle by which to conduct this aspect of the business).

OHL and Green Pathways intend to develop a viable arrangement with suppliers and installers of Renewable Energy packages, have them complete the installation, certification and commissioning and provide after sales, in-service/product support. OHL and Green Pathways Inc. would perform initial suitability and viability assessments. It would also make the prospective participant aware of issues such as installation specific insurance requirements.

OHL proposes that every effort and preference will be given to sourcing Ontario and Canadian designed and manufactured products since it is known that such sources exist for both solar powered and wind powered products.

OHL anticipates there will be a market for approximately 800 small-scale generation installations. This potential demand would create full-time jobs for 2 installation / maintenance technicians, 1 engineer, 1 administration person, and 1 marketing person.

There are two candidate acquisition and installation scenarios. 'Get you Started' and Lease to own/rent to own installations:

The goal of these Programs is to achieve the maximum number of residential and small business installations of less than 10 kWs (MicroFIT Program) and thereby have a significant influence on future electricity demand. i.e. its reduction. Initially this might be restricted to solar PV since it will be offered only in the towns of Orangeville and Grand Valley. It could then be expanded to include wind turbines for more rural installations with suitable wind conditions.

GET YOU STARTED INSTALLATION

The system would be offered as an installed 'starter kit' package of modest size, e.g. single panel – 160W, but would have provision to be scaled up incrementally, should the Participant wish, at their cost and could then conform to the terms and conditions of the Lease to Own/Rent to Own program . The Program would be marketed, managed, delivered and installed similarly to the PSB program. i.e. a Provincial government sponsored and funded program, offered by the OEB/OPA and delivered by OHL and or its Agent. The program application and installation permit application would be made by the prospective participant as identified in the MicroFIT Program.

LEASE TO OWN / RENT TO OWN INSTALLATION

In this program, the applicant identifies the size/capacity of the system of interest and makes application through the MicroFIT Program. Any costs or charges associated with the determination of site suitability and viability would be borne by the proponent. Green Pathways will co-ordinate the installation, grid-tie and commissioning of a system of defined capacity.

SUCCESS INDICATORS AND TARGETS

- Growth of sales in DG packages;
- Positive customer feedback and favourable ROI; and,
- Smooth integration of DG into Smart Grid.

FINANCIAL IMPLICATIONS

All detail materials, installation and tie-in labor, certification and commissioning costs would be transparent to the participant. These costs would be recovered through FIT's. This could be in the form of an interest bearing loan and the transaction conducted as part of the monthly billing process.

GOAL 6: LARGE RENEWABLES

SITUATION/STRATEGY

In partnering and investing in small renewables generation with commercial or industrial businesses, OHL will be supporting the local industry and furthering its objective of becoming a “green” leader amongst similar sized communities.

Presently there are no large-scale generation projects planned for our service territory. However, there are large-scale projects planned in Hydro One’s territory adjacent to our service areas that have already allocated all of the available capacity through RESOP. Some developers of these projects have requested direct connection to OHL. Should a large-scale project emerge, we may have to expedite voltage conversion plan and /or build additional 3 phase circuits.

Partnering with commercial or industrial customers to develop solar or wind projects fits in our long range Year 6-11 year plan. Business cases for investing in Renewable Generation jointly with Commercial/Industrial customers are required before they begin. This may include analysis of opportunities for sharing of risk and LDC financing of projects which might not otherwise be developed. The main reason this goal is within the 2-5 year time horizon is because the grid is currently constrained – the time of project commencement assumes transmission constraint will be resolved by Hydro One and new capacity will be accessible.

STRATEGY

As a first step for large renewables we propose building and operating our own Distributed Generation facility and feeding electricity back to the grid. We would like to build and own our own Distributed Generation System to pilot the renewable distributed generation concept. A renewable generation system with the maximum allowed generating capacity under the Green Energy Act will be considered. OHL will conduct a feasibility study for the project to determine the optimal generating capacity (which may be significantly less than 10 MW).

After OHL has successfully completed and connected its large Distributed Generation project, it anticipates having the necessary infrastructure in place to start connecting other Distributed Generation to its grid. OHL will continue growing its distribution system and make the administrative, standards, metering, and generating capacity investments while it is developing its own Distributed Generation facility. Additionally, we would like to create a business case for creating a “green” commercial park.

OTHER COLLABORATIVE LARGE SCALE RENEWABLE PROJECTS

There are a number of possible collaborative projects, some of which may qualify as ‘community’ that are of interest to OHL, collaborating with Green Pathways Inc. and OHL customers. It is OHL’s intention, together with Green Pathways Inc., to be pro-active in communicating potential projects within the community and identifying prospective candidate partners who can take advantage of and benefit from programs facilitated by the GEA.

Apart from wind and solar based electricity generating systems, OHL is now aware of a small-scale bio-waste system (suitable for hospitals, schools, nursing homes, hotels for example) which would significantly reduce the requirement to landfill waste products that cannot be recycled or are not suitable for composting.

Examples of Potential Collaborative/Partnership Projects include:

School Premises – Participating in the grade 5 Green Schools Pilot Initiative; a collaborative project/program that is attractive to Orangeville Hydro and Green Pathways, is the recently announced Green Schools Pilot Initiative. This Initiative has a number of aspects, green electricity generation being just one, where we could participate in an effective and constructive way. By working with both the Upper Grand District School Board and the Catholic School Board together and a team of competent ‘partners’, we can help deliver significant benefits to the School Boards and school premises in the area.

The next step is to contact the Schools Boards to determine whether they are interested in participating in a Science Fair Event and whether they have indicated this to the Ministry of Education.

Flat Roofed Buildings: There are a significant number of buildings in Orangeville with flat or shallow rise roofs. The potential exists to install a solar PV system designed specifically for these types of roofs.

This could be under 3 scenarios:

- OHL rents or leases the roof area and installs, owns and operates the system;
- OHL, in partnership with the building owner installs, owns and operates the system; and,
- The building owner installs, owns and operates the system. (The building owner contracts with OHL/Green Pathways Inc. to procure, install, grid-tie and commission the system).

“Total Solution” Type Opportunities: The potential exists to propose a renewable energy based generation system that could conceivably comprise elements of wind, solar and bio-waste and be supplemented by solar water heating and drain water heat recovery. Examples include:

- Headwaters Healthcare Centre, Best Western Hotel and Elizabeth Street Seniors Residence.

FINANCIAL IMPLICATIONS

Although these renewable projects will be funded through the LDC, any investment through partnerships will increase the risk profile and reduce control. Furthermore, since these are strategic partnerships, the wise choice of partners is critical to ensuring that achieve the benefits identified in the applicable business case.

3.4 RISK PROFILES OF INVESTMENTS

With limiting resources and competing priorities, risks and constraints are an essential factor. It is critically important that risk and return be balanced with the likelihood of success for the project initiatives. In exploring a projects risk profile, it is important to consider the regulatory, financial, and operation implications of each investment.

Table 2 - High level financial, regulatory, and operational implications of strategic goals

Goals & Activities	Financial Implications	Regulatory Implications	Operational Implications
Goal 1 Activities: SCADA; Remote Sensing; Motorized Switches; Engineering Design; PME Installs; In Home Controls; Remote Disconnect	Investments in infrastructure recoverable through rates application	Smart Meters and TOU are mandatory; system upgrades and the replaced of 4 kV feeder will need to be phased in	Increased complexity and new full time employees
Goal 2 Activities: FIT Enablement; CIS Upgrades and other essential components	Distribution upgrades will be submitted to OEB for approval. Any transmission upgrades are to be developed with Hydro One Support	Main control mechanism for FIT program under OPA is project readiness, need for T&D connection upgrades, and deposits	LDCs have established a working group for FIT developed through EDA; used to educate LDCs regarding their role roles and responsibilities under FIT program
Goal 3 Activities: Continue to support current OEB, Ministry and OPA objectives. Proposed DR programs OHL will explore include: • DR1 • DR2 • DR3	Recovery of capital investment must be ensured	Verifiable results can be achieved through LRAM incentive	Customer communications implications
Goal 4 Activities: Educate the following market segments: • Business/Industry Institutions and Associations • Schools and Educational Facilities • Residential Homeowners • Low Income and Seniors	Ongoing capital and operational expenditure	N/A	Marketing campaigns and seminars will be delivered through OHL in conjunction with its affiliate, Green Pathways Inc.
Goal 5 Activities: In conjunction with Goal 2 Activities Above	There will be minimal financial risk to OHL since price will be known in advance and main revenue will come from FIT contracts and not at the expense of the LDC	Grid currently constrained; pending additional Hydro One capacity	Strong relationship with customers is critical in selling renewables through turnkey operations
Goal 6 Activities: OHL owned large renewable (On-site); Other large renewables	Partner with third party to share financial risk	Ensure approval to include in rate base	Not a core competency; employee expertise and knowledge transfer required

3.5 LONG-TERM STRATEGIC GOALS (YEARS 6-11)

CAP AND TRADE

The objective of the Cap-and-Trade program is to reduce emissions at the lowest possible cost. Green House Gas (GHG) emissions from large emitters or sources are capped at a designated level. Parties that emit GHGs above a threshold (25,000 tonnes/ yr CO2) are called regulated emitters. OHL is not a regulated emitter therefore CDM activities may create opportunities to develop Carbon Offsets.

Our plan is to Investigate which type of baselines need to be established and which type of metering equipment will be required. Using this information we can determine which type of initiatives can be aggregated and sold depending on the market value in that point in time - choose to hold until opportune time to sell.

Potential markets for carbon offsets are assumed to be $12-15/tonnes, meaning it could be a significant revenue stream. The Cap-and-Trade revenues could offset CDM costs or promote further investment and other strategic goals.

COMBINED HEAT AND POWER

The combined Heat and Power projects will be completed in partnership with Commercial and Industrial Customers. Eligible FIT programs can be completed, either separately, or in combination with heat and power. OHL's Commercial/Industrial customers do not have the expertise to carry out the projects.

With a sufficient feed stock, combined heat and power is an efficient and productive method to produce energy for and recycle the heat of an industrial commercial application. This solves the feed stock problem - as long as the customer continues to use the facility.

In partnership, there are risk and control implications for the Commercial or Industrial business. For example, the plant could shut down or relocate and the feed stock could disappear.

WASTE ENERGY OPTIONS

The waste energy Renewable Generation source is not a high priority for Municipal Governments since generating energy from waste does not support their diversion targets - this will need to be resolved between the Ministries of Energy and Environment. OHL will explore opportunities with local municipalities when the government policy is identified.

ELECTRIC VEHICLES

The Green Energy Act is essentially silent on green or electrically powered vehicles but does mention transportation fuels in the context of reduction of use. There are issues that must be addressed if "Green" electric and hybrid electric vehicles are to be made widely available to the public in the next few years, including:

- Communication and billing;
- Impact assessment;
- Incenting customers;
- Preparing and upgrading the grid;
- Establishing commercial fueling stations;
- Policy development for the transport sector; and,
- Provision of training for the above.

OHL wishes to commence a study in 2010 that will address all the issues above as well as the following modes of transportation, shown below.

- **Scooters and Motorcycles:** Electric scooters and motorcycles are now becoming more prominent. Dealerships are being established and model and type availability is quite diverse. Orangeville has two sales outlets for these types of vehicles;

- **Personal Vehicles:** Currently, there is much publicity regarding the development by virtually every vehicle manufacturer of electric personal vehicles. Various technical challenges and issues still need to be addressed and solved and the vehicles need to be approved to operate on the roads of Ontario;

- **Commercial Vehicles:** Less is publicized about electric commercial vehicles but as with electric passenger vehicles they are being developed. One company that comes to mind is Smith located in the U.K which has an affiliation with the Ford Motor Company. Smith has recently established an assembly plant in the United States and will offer electric commercial vehicles under the Ford badge and through selected Ford dealerships. This, further, reinforces the OHL interest in developing a charging and battery regeneration system for electric vehicles; and,

- **Public Transit Vehicles:** Orangeville operates a small fleet of public transit vehicles. During years 2 - 4 of this Plan OHL would like to conduct research and investigation of the cost / benefit of converting the town's buses to electric propulsion.

It is anticipated that Green vehicles such as electric, solar/electric, hydrogen and air, will become available for consumers to purchase during the long term period of performance of this Plan. OHL proposes to investigate the requirement for and if appropriate establish a service/support capability for these types of vehicles. It also has identified a small knowledge and experience acquisition project that would be suitable for high schools and community colleges to undertake.

Overall, as these vehicles increase in popularity and availability, this market/business sector will represent both business and job creation opportunities in the area of sales, product support/maintenance and training.

SETUP GENERATION ARM

As OHL develops expertise in Renewable Generation, through partnerships with generators and Commercial/Industrial customers, it may become a relative competitive advantage. At this point OHL may choose to setup an affiliate devoted to Renewable Generation and remove any future projects from utility rate base. This is an opportunity for Orangeville to diversify shareholder business.

4 WORK PLAN, MILESTONES, AND TIMELINE

Upon submission of this enabler plan, OHL anticipates OEB approval within 1 month. The 3-6 months following approval, OHL anticipates OEB will begin funding and resolving resourcing issues. Once funding and resolving issues have been addressed, OHL will begin commencing execution.

In the months leading up to January 1, 2010, OHL will do the following:

- Name/identify internal Champions and Proponents;
- Seek unanimous buy-in and support from the OHL Board as well as Orangeville Town Council (*This action will informally be achieved prior to Plan submission to OEB however upon OEB approval we will seek official support);*
- Finalize budgets (both capital and operating) to enable execution of plan, specifically:
  - Within 90 days of receiving Plan approval there are funds available to cover Year 1 capital and operating expenses, and with source of funds determined for Years 2 to 5;
  - Within 90 days of receiving Plan approval a detailed operating budget has been developed and approved for Year 1;
- Form its Management Teams required to implement the strategic goals; and,
- Begin initial discussion with key strategic partners.

A proposed Work Plan has been completed for the short-term (Year 1-5) strategic goals. The plan is subject to change, in accordance to regulatory, operational, or financial developments.

The Activities under each goal and our proposed Work Plan and Timeframe with respect to each, is shown in Table 3, below.

Table 3 – Work Plan, Milestones, and Timeline

	Activities	Work Plan, Timeframe and Milestones
Goal 1 - Develop Smart Grid Infrastructure and Installation of Smart Meters:	Install and implement the following: • SCADA; Remote Sensing; Motorized Switches • Engineering Design; PME Installs; In Home Controls; Remote Disconnect • Review and update work Safety Manuals, Operating Policies and Practices	Year 1 -Have engaged the resources necessary to commence the design and engineering of a Smart Grid infrastructure and begin procurement of Smart Meters for Orangeville and Grand Valley.

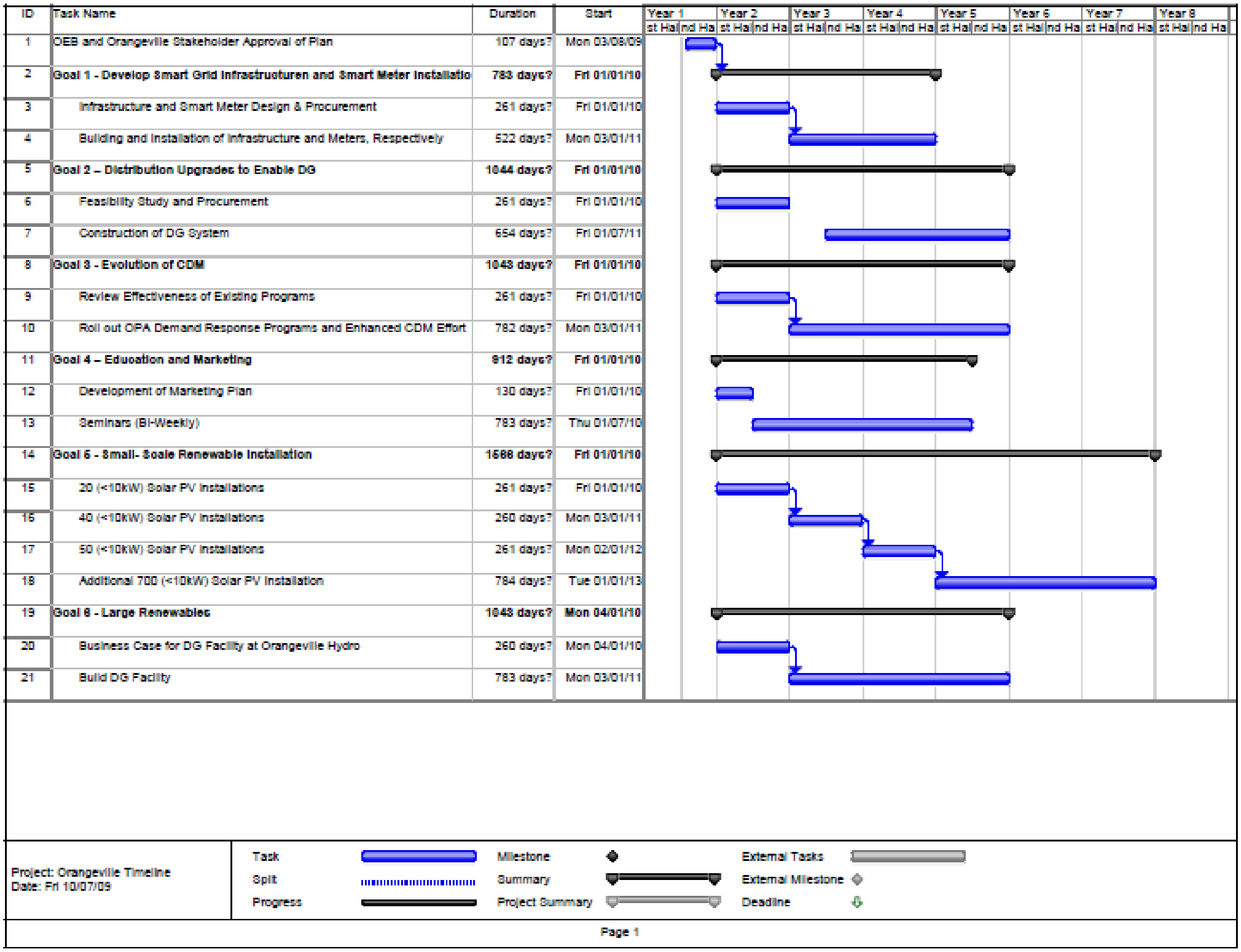
Goal 2 - Distribution Upgrades to enable DG	Install and implement the following:
	• FIT Enablement
	• CIS Upgrades and other essential components including:
	  • Meter technology
	  • ESA requirements for meter locations
		Our strategy is to complete a feasibility study in Year 1 to determine if the project is viable. If the project is feasible, construction of the project would begin at year 2. By the 2nd quarter of Year 3 construction of the distributed generation will commence.

Goal 3 – Evolution of CDM	Continue to support current OEB, Ministry and OPA objectives. Proposed DR programs OHL will explore include: • DR1 • DR2 • DR3	Time is spent in Year 1 to properly review the effectiveness of existing programs and Initiatives as they are being participated in, by OHL's customers to determine whether they are achieving their desired goals. The existing programs and initiatives would, of course, continue while this task is being conducted. The rollout of the new CDM initiatives is proposed to occur during the five years following the review of existing programs.

Goal 4 – Marketing Campaign	Educate the following market segments: • Business/Industry Institutions and Associations • Schools and Educational Facilities • Residential Homeowners • Low Income and Seniors	This will require the services of a professional website developer and access to subject matter experts. Planning will commence in Year 1 with incremental completion milestones over an 18 month period. In order to educate the customers on Smart Meters, CDM, and Renewable Generation we propose running seminars for the next two years. By the end of Year 2, all customers of OHL will have been made aware of what is contained within this Plan, how they will be affected and what's in it for them.
Goal 5 – Small-Scale Renewables Installation	See Goal 2 Activities Above	The work plan for Small-Scale Renewable Generation can be summed up by the number of new small renewables being proposed in consecutive timeframes: • By the end of Year 2 to have up to 300 <10kW solar PV installations in place with up to 5 of those including wind power; • By the end of Year 3 to have a further 200 <10kW solar PV installations in place with 20% including wind power; • By the end of Year 4 to have a further 100 <10kW solar PV installations in place with 20% including wind power; and, • Between Year 5 and 11 have installations increase year over year in order that the goal of a minimum of 800 installations is achieved. Note: This represents an estimated installation rate of approximately 3 per week.
Goal 6 – Large-Scale Renewables Installation	• OHL owned large renewable (On-site) • Other large renewables	Large Renewables - By the end of Year 2 we will have completed the business case study for an up to 10MW (size optimized) distributed generation facility owned and operated by OHL. Once the business case has been completed and approved, OHL anticipates that the installation will require 2-3 years to complete.

EXECUTION OF GEA INITIATIVES

Figure 3 - Proposed timeline for activities



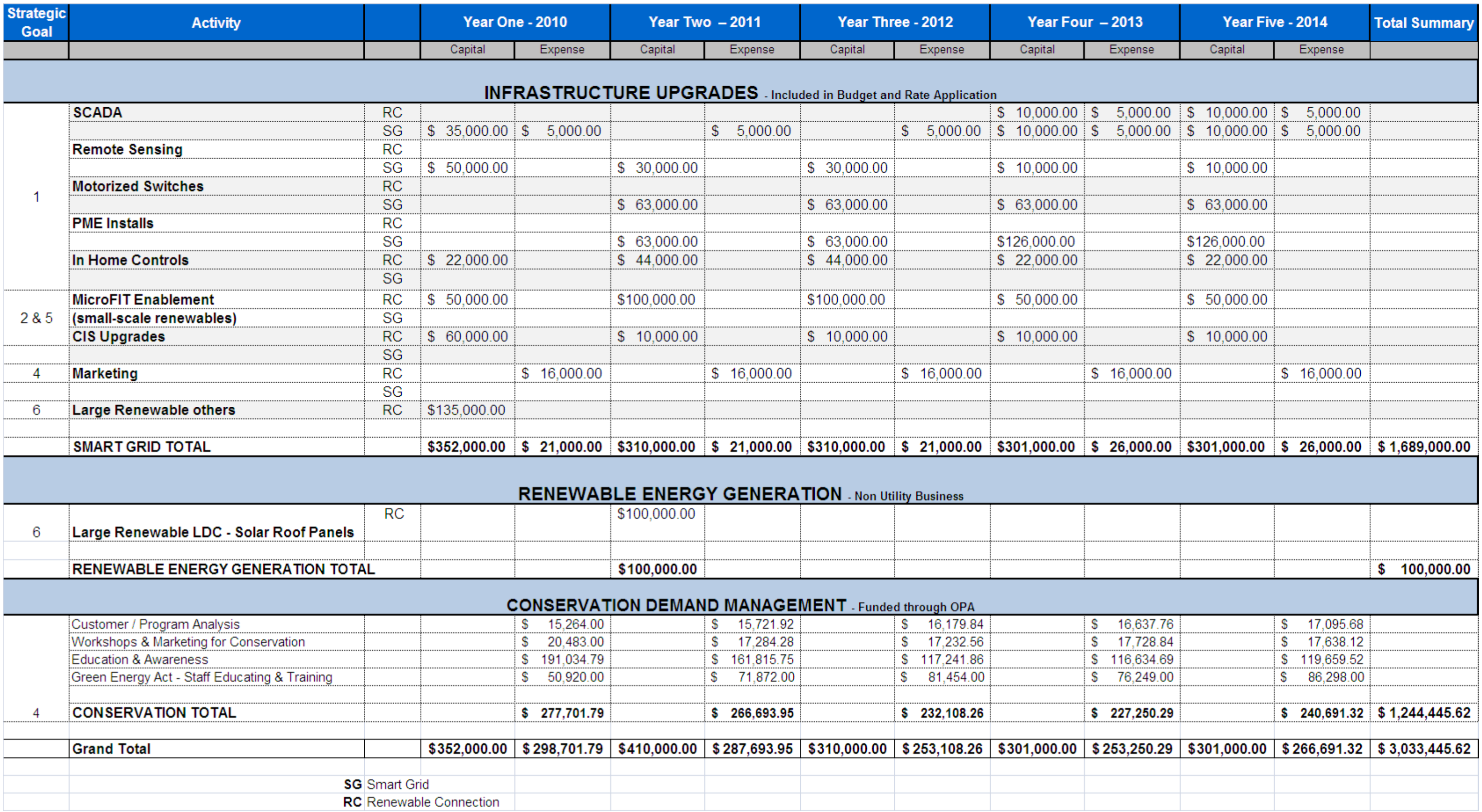
ID	Task Name	Duration	Start
1	OEB and Orangeville Stakeholder Approval of Plan	107 days?	Mon 03/08/09
2	**Goal 1 - Develop Smart Grid Infrastructuren and Smart Meter Installatio**	**783 days?**	**Fri 01/01/10**
3	Infrastructure and Smart Meter Design & Procurement	261 days?	Fri 01/01/10
4	Building and Installation of Infrastructure and Meters, Respectively	522 days?	Mon 03/01/11
5	**Goal 2 – Distribution Upgrades to Enable DG**	**1044 days?**	**Fri 01/01/10**
6	Feasibility Study and Procurement	261 days?	Fri 01/01/10
7	Construction of DG System	654 days?	Fri 01/07/11
8	**Goal 3 - Evolution of CDM**	**1043 days?**	**Fri 01/01/10**
9	Review Effectiveness of Existing Programs	261 days?	Fri 01/01/10
10	Roll out OPA Demand Response Programs and Enhanced CDM Effort	782 days?	Mon 03/01/11
11	**Goal 4 – Education and Marketing**	**912 days?**	**Fri 01/01/10**
12	Development of Marketing Plan	130 days?	Fri 01/01/10
13	Seminars (Bi-Weekly)	783 days?	Thu 01/07/10
14	**Goal 5 - Small- Scale Renewable Installation**	**1566 days?**	**Fri 01/01/10**
15	20 (<10kW) Solar PV Installations	261 days?	Fri 01/01/10
16	40 (<10kW) Solar PV Installations	260 days?	Mon 03/01/11
17	50 (<10kW) Solar PV Installations	261 days?	Mon 02/01/12
18	Additional 700 (<10kW) Solar PV Installation	784 days?	Tue 01/01/13
19	**Goal 6 - Large Renewables**	**1043 days?**	**Mon 04/01/10**
20	Business Case for DG Facility at Orangeville Hydro	260 days?	Mon 04/01/10
21	Build DG Facility	783 days?	Mon 03/01/11

Project: Orangeville Timeline
Date: Fri 10/07/09

Page 1

5 BUDGET & RESOURCES

Table 4 - Costs associated with implementing Smart Grid



Strategic Goal	Activity		Year One - 2010		Year Two – 2011		Year Three - 2012		Year Four – 2013		Year Five - 2014		Total Summary
			Capital	Expense	Capital	Expense	Capital	Expense	Capital	Expense	Capital	Expense	
	INFRASTRUCTURE UPGRADES - Included in Budget and Rate Application												
1	**SCADA**	RC							$ 10,000.00	$ 5,000.00	$ 10,000.00	$ 5,000.00	
		SG	$ 35,000.00	$ 5,000.00		$ 5,000.00		$ 5,000.00	$ 10,000.00	$ 5,000.00	$ 10,000.00	$ 5,000.00	
	Remote Sensing	RC											
		SG	$ 50,000.00		$ 30,000.00		$ 30,000.00		$ 10,000.00		$ 10,000.00		
	Motorized Switches	RC											
		SG			$ 63,000.00		$ 63,000.00		$ 63,000.00		$ 63,000.00		
	PME Installs	RC											
		SG			$ 63,000.00		$ 63,000.00		$126,000.00		$126,000.00		
	In Home Controls	RC	$ 22,000.00		$ 44,000.00		$ 44,000.00		$ 22,000.00		$ 22,000.00		
		SG											
2 & 5	**MicroFIT Enablement**	RC	$ 50,000.00		$100,000.00		$100,000.00		$ 50,000.00		$ 50,000.00		
	(small-scale renewables)	SG											
	CIS Upgrades	RC	$ 60,000.00		$ 10,000.00		$ 10,000.00		$ 10,000.00		$ 10,000.00		
		SG											
4	**Marketing**	RC		$ 16,000.00		$ 16,000.00		$ 16,000.00		$ 16,000.00		$ 16,000.00	
		SG											
6	**Large Renewable others**	RC	$135,000.00										
	SMART GRID TOTAL		**$352,000.00**	**$ 21,000.00**	**$310,000.00**	**$ 21,000.00**	**$310,000.00**	**$ 21,000.00**	**$301,000.00**	**$ 26,000.00**	**$301,000.00**	**$ 26,000.00**	**$ 1,689,000.00**
	RENEWABLE ENERGY GENERATION - Non Utility Business												
6	**Large Renewable LDC - Solar Roof Panels**	RC			$100,000.00								
	RENEWABLE ENERGY GENERATION TOTAL				**$100,000.00**								**$ 100,000.00**
	CONSERVATION DEMAND MANAGEMENT - Funded through OPA												
4	Customer / Program Analysis			$ 15,264.00		$ 15,721.92		$ 16,179.84		$ 16,637.76		$ 17,095.68	
	Workshops & Marketing for Conservation			$ 20,483.00		$ 17,284.28		$ 17,232.56		$ 17,728.84		$ 17,638.12	
	Education & Awareness			$ 191,034.79		$ 161,815.75		$ 117,241.86		$ 116,634.69		$ 119,659.52	
	Green Energy Act - Staff Educating & Training			$ 50,920.00		$ 71,872.00		$ 81,454.00		$ 76,249.00		$ 86,298.00	
	CONSERVATION TOTAL			**$ 277,701.79**		**$ 266,693.95**		**$ 232,108.26**		**$ 227,250.29**		**$ 240,691.32**	**$ 1,244,445.62**
	Grand Total		**$352,000.00**	**$ 298,701.79**	**$410,000.00**	**$ 287,693.95**	**$310,000.00**	**$ 253,108.26**	**$301,000.00**	**$ 253,250.29**	**$301,000.00**	**$ 266,691.32**	**$ 3,033,445.62**
	SG	Smart Grid											
	RC	Renewable Connection											

RC = Renewable Connection

SG = Smart Grid

See Appendix 1 for a breakdown of CDM Budget Estimates

6 CORPORATE EVOLUTION

It is believed that during the Work Plan, OHL will need to change its corporate structure to effectively execute the various activities described in the Plan. In fundamental terms, over time, the functions will evolve into three areas: distribution, generation, and services. These are a variety of corporate structures – from operating divisions of OHL to affiliated stand alone entities – that may be suitable.

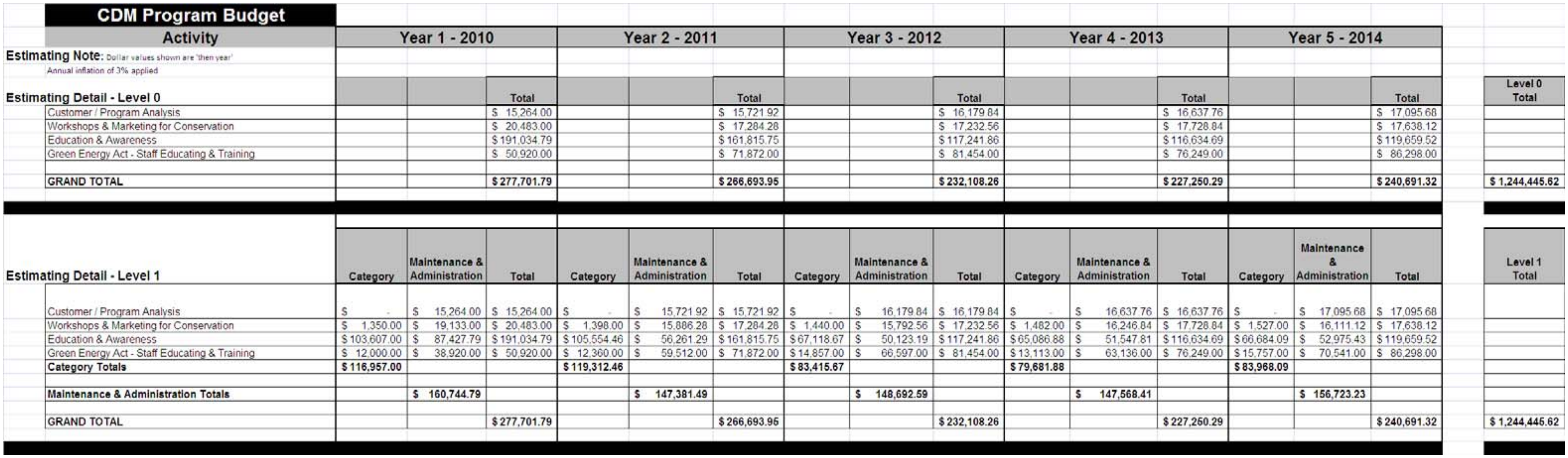
The distribution function will be similar to the prevailing business mandate with the added responsibility of designing, engineering, developing, installing, operating and maintaining the Smart Grid. It will be responsible for the adequate supply of secure, reliable and quality electricity to its ever-growing customer base. It will also be responsible for billing customers, settlement and collecting monies.

A potentially new function will be that of electricity generation, primarily using renewable resources such as solar, wind and, perhaps, bio-waste/bio-mass. To execute this effectively it may be appropriate to establish a separate business entity with a unique mandate to provide reliable, quality electricity up to the capacity of 10 MW.

A third function would be that of provision of services to a 40,000 customer base. However, the core customer base would be that of OHL. This business division would be similar in function to and could incorporate Green Pathways Inc. subsidiary. It would be the One-Stop-Shop. This entity would perhaps assume the responsibility for maintaining the street lighting. Its other activities would include conservation program delivery, conservation and energy management programs, consumer education and awareness, green power installations outside of the 10 MW system and other green energy related consumer products and services.

APPENDIX

Appendix 1 - CDM Budget Estimates



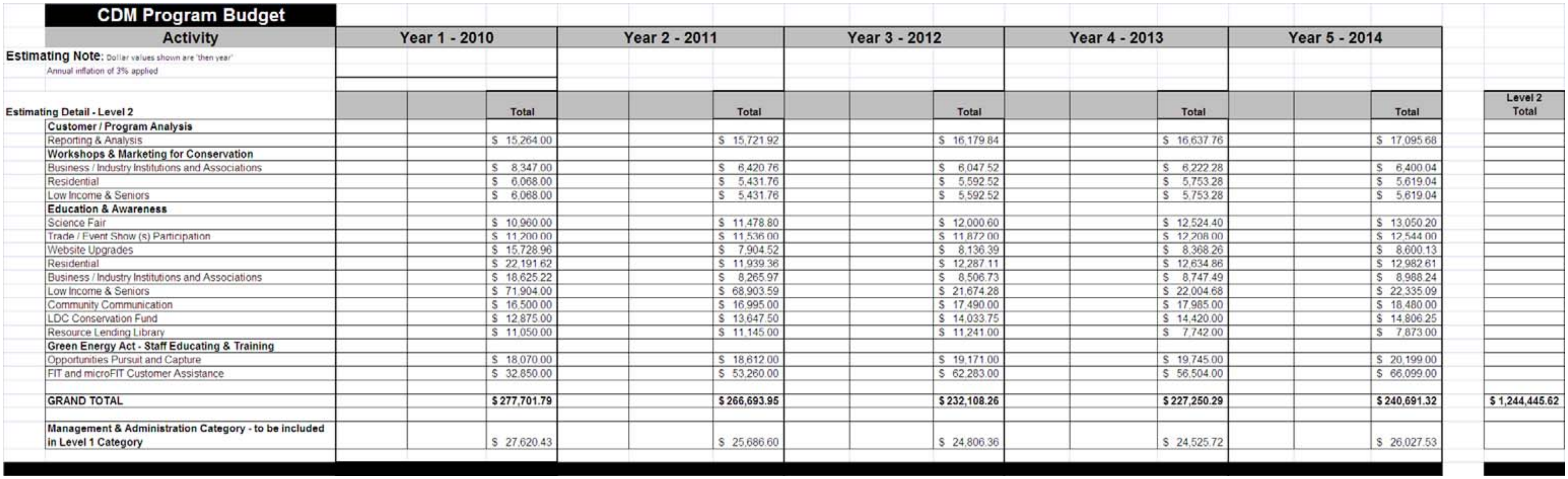
CDM Program Budget

Estimating Note: Dollar values shown are 'then year'
Annual inflation of 3% applied

Activity	Year 1 - 2010			Year 2 - 2011			Year 3 - 2012			Year 4 - 2013			Year 5 - 2014			
Estimating Detail - Level 0			Total			Total			Total			Total			Total	Level 0 Total
Customer / Program Analysis			$ 15,264.00			$ 15,721.92			$ 16,179.84			$ 16,637.76			$ 17,095.68	
Workshops & Marketing for Conservation			$ 20,483.00			$ 17,284.28			$ 17,232.56			$ 17,728.84			$ 17,638.12	
Education & Awareness			$ 191,034.79			$ 161,815.75			$ 117,241.86			$ 116,634.69			$ 119,659.52	
Green Energy Act - Staff Educating & Training			$ 50,920.00			$ 71,872.00			$ 81,454.00			$ 76,249.00			$ 86,298.00	
GRAND TOTAL			$ 277,701.79			$ 266,693.95			$ 232,108.26			$ 227,250.29			$ 240,691.32	$ 1,244,445.62

Estimating Detail - Level 1	Category	Maintenance & Administration	Total	Category	Maintenance & Administration	Total	Category	Maintenance & Administration	Total	Category	Maintenance & Administration	Total	Category	Maintenance & Administration	Total	Level 1 Total
Customer / Program Analysis	$ -	$ 15,264.00	$ 15,264.00	$ -	$ 15,721.92	$ 15,721.92	$ -	$ 16,179.84	$ 16,179.84	$ -	$ 16,637.76	$ 16,637.76	$ -	$ 17,095.68	$ 17,095.68	
Workshops & Marketing for Conservation	$ 1,350.00	$ 19,133.00	$ 20,483.00	$ 1,398.00	$ 15,886.28	$ 17,284.28	$ 1,440.00	$ 15,792.56	$ 17,232.56	$ 1,482.00	$ 16,246.84	$ 17,728.84	$ 1,527.00	$ 16,111.12	$ 17,638.12	
Education & Awareness	$ 103,607.00	$ 87,427.79	$ 191,034.79	$ 105,554.46	$ 56,261.29	$ 161,815.75	$ 67,118.67	$ 50,123.19	$ 117,241.86	$ 65,086.88	$ 51,547.81	$ 116,634.69	$ 66,684.09	$ 52,975.43	$ 119,659.52	
Green Energy Act - Staff Educating & Training	$ 12,000.00	$ 38,920.00	$ 50,920.00	$ 12,360.00	$ 59,512.00	$ 71,872.00	$ 14,857.00	$ 66,597.00	$ 81,454.00	$ 13,113.00	$ 63,136.00	$ 76,249.00	$ 15,757.00	$ 70,541.00	$ 86,298.00	
Category Totals	**$ 116,957.00**			**$ 119,312.46**			**$ 83,415.67**			**$ 79,681.88**			**$ 83,968.09**			
Maintenance & Administration Totals		**$ 160,744.79**			**$ 147,381.49**			**$ 148,692.59**			**$ 147,568.41**			**$ 156,723.23**		
GRAND TOTAL			$ 277,701.79			$ 266,693.95			$ 232,108.26			$ 227,250.29			$ 240,691.32	$ 1,244,445.62

RC = Renewable Connection
SG = Smart Grid



CDM Program Budget

Estimating Note: Dollar values shown are 'then year'
Annual inflation of 3% applied

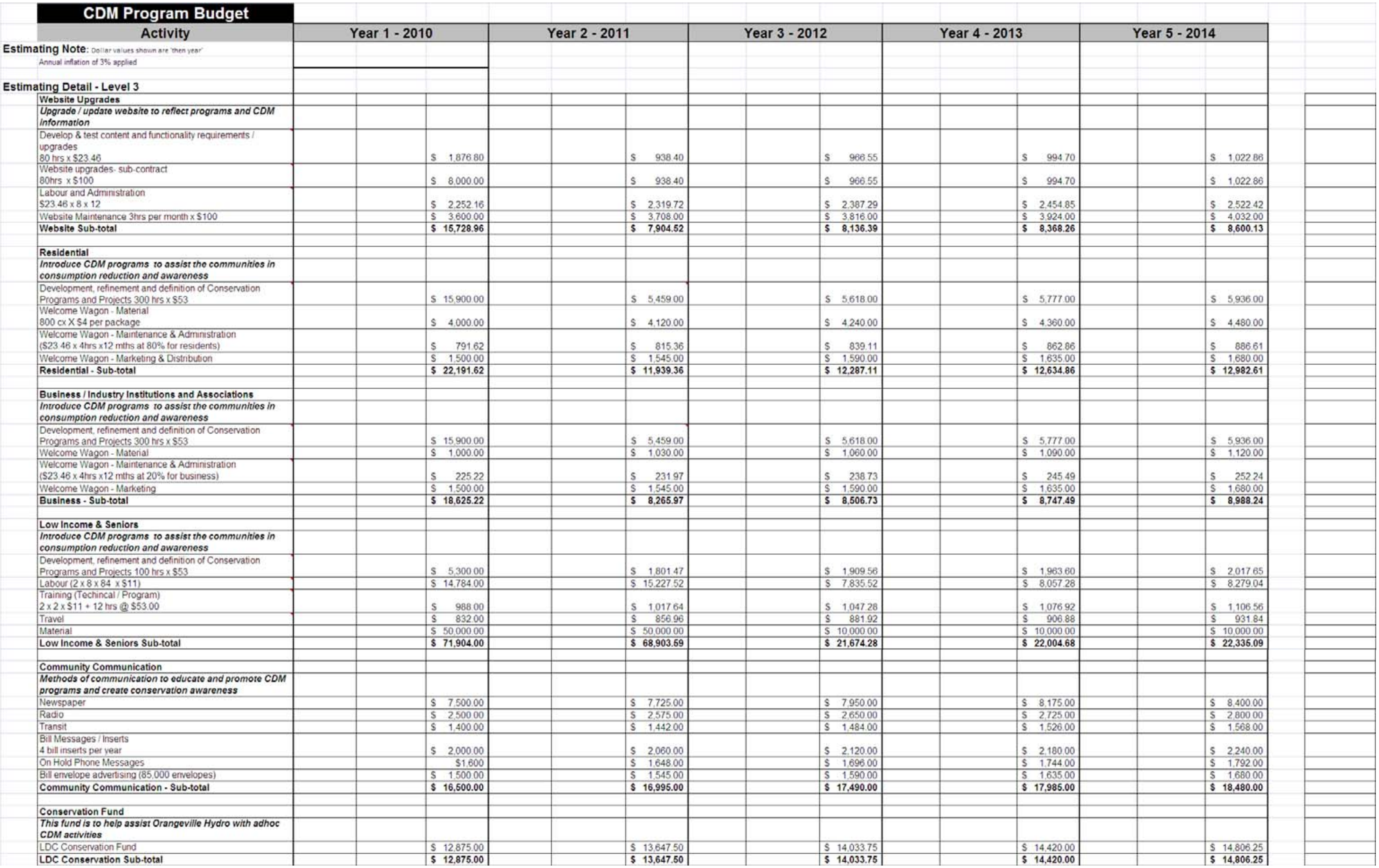
Activity	Year 1 - 2010			Year 2 - 2011			Year 3 - 2012			Year 4 - 2013			Year 5 - 2014			
Estimating Detail - Level 2			**Total**			**Total**			**Total**			**Total**			**Total**	**Level 2 Total**
Customer / Program Analysis																
Reporting & Analysis			$ 15,264.00			$ 15,721.92			$ 16,179.84			$ 16,637.76			$ 17,095.68	
Workshops & Marketing for Conservation																
Business / Industry Institutions and Associations			$ 8,347.00			$ 6,420.76			$ 6,047.52			$ 6,222.28			$ 6,400.04	
Residential			$ 6,068.00			$ 5,431.76			$ 5,592.52			$ 5,753.28			$ 5,619.04	
Low Income & Seniors			$ 6,068.00			$ 5,431.76			$ 5,592.52			$ 5,753.28			$ 5,619.04	
Education & Awareness																
Science Fair			$ 10,960.00			$ 11,478.80			$ 12,000.60			$ 12,524.40			$ 13,050.20	
Trade / Event Show (s) Participation			$ 11,200.00			$ 11,536.00			$ 11,872.00			$ 12,208.00			$ 12,544.00	
Website Upgrades			$ 15,728.96			$ 7,904.52			$ 8,136.39			$ 8,368.26			$ 8,600.13	
Residential			$ 22,191.62			$ 11,939.36			$ 12,287.11			$ 12,634.86			$ 12,982.61	
Business / Industry Institutions and Associations			$ 18,625.22			$ 8,265.97			$ 8,506.73			$ 8,747.49			$ 8,988.24	
Low Income & Seniors			$ 71,904.00			$ 68,903.59			$ 21,674.28			$ 22,004.68			$ 22,335.09	
Community Communication			$ 16,500.00			$ 16,995.00			$ 17,490.00			$ 17,985.00			$ 18,480.00	
LDC Conservation Fund			$ 12,875.00			$ 13,647.50			$ 14,033.75			$ 14,420.00			$ 14,806.25	
Resource Lending Library			$ 11,050.00			$ 11,145.00			$ 11,241.00			$ 7,742.00			$ 7,873.00	
Green Energy Act - Staff Educating & Training																
Opportunities Pursuit and Capture			$ 18,070.00			$ 18,612.00			$ 19,171.00			$ 19,745.00			$ 20,199.00	
FIT and microFIT Customer Assistance			$ 32,850.00			$ 53,260.00			$ 62,283.00			$ 56,504.00			$ 66,099.00	
GRAND TOTAL			**$ 277,701.79**			**$ 266,693.95**			**$ 232,108.26**			**$ 227,250.29**			**$ 240,691.32**	**$ 1,244,445.62**
Management & Administration Category - to be included in Level 1 Category			$ 27,620.43			$ 25,686.60			$ 24,806.36			$ 24,525.72			$ 26,027.53	

RC = Renewable Connection
SG = Smart Grid

CDM Program Budget

Activity	Year 1 - 2010	Year 2 - 2011	Year 3 - 2012	Year 4 - 2013	Year 5 - 2014	
Estimating Note: Dollar values shown are 'then year'						
Annual inflation of 3% applied						
Estimating Detail - Level 3						
Customer / Program Analysis	**Total**	**Total**	**Total**	**Total**	**Total**	**Level 3 Total**
Reporting and Analysis						
Prepare and deliver reporting & analysis						
Administration - Reporting & Analysis 24x12x$53.00	$ 15,264.00	$ 15,721.92	$ 16,179.84	$ 16,637.76	$ 17,095.68	
Analysis Sub-total	**$ 15,264.00**	**$ 15,721.92**	**$ 16,179.84**	**$ 16,637.76**	**$ 17,095.68**	
Workshops & Marketing for Conservation						
Business / Industry Institutions and Associations						
Prepare and deliver information sessions on a regular basis						
Prepare material 60 x $53.00	$ 3,180.00	$ 1,092.00	$ 562.00	$ 579.00	$ 597.00	
Deliver information sessions 8 x 2 x 2 x $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Post session response 8 x 2 x 2 X $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Meetings/communications etc. 25 x 1 x $53	$ 1,325.00	$ 1,365.00	$ 1,406.00	$ 1,448.00	$ 1,491.00	
Materials	$ 200.00	$ 210.00	$ 216.00	$ 222.00	$ 229.00	
Travel	$ 250.00	$ 260.00	$ 268.00	$ 276.00	$ 284.00	
Business Sub-total	**$ 8,347.00**	**$ 6,420.76**	**$ 6,047.52**	**$ 6,222.28**	**$ 6,400.04**	
Residential						
Prepare and deliver information sessions on a regular basis						
Prepare material 30 x $53.00	$ 1,590.00	$ 819.00	$ 844.00	$ 869.00	$ 597.00	
Deliver information sessions 8 x 2 x 2 x $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Post session response 8 x 2 x 2 X $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Meetings/communications etc. 12 x 1 x $53	$ 636.00	$ 655.00	$ 675.00	$ 695.00	$ 716.00	
Materials	$ 200.00	$ 206.00	$ 212.00	$ 218.00	$ 225.00	
Travel	$ 250.00	$ 258.00	$ 266.00	$ 274.00	$ 282.00	
Residential Sub-total	**$ 6,068.00**	**$ 5,431.76**	**$ 5,592.52**	**$ 5,753.28**	**$ 5,619.04**	
Low Income & Seniors						
Prepare and deliver information sessions on a regular basis						
Prepare material 30 x $53.00	$ 1,590.00	$ 819.00	$ 844.00	$ 869.00	$ 597.00	
Deliver information sessions 8 x 2 x 2 x $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Post session response 8 x 2 x 2 X $53.00	$ 1,696.00	$ 1,746.88	$ 1,797.76	$ 1,848.64	$ 1,899.52	
Meetings/communications etc 12 x1 x $53	$ 636.00	$ 655.00	$ 675.00	$ 695.00	$ 716.00	
Material	$ 200.00	$ 206.00	$ 212.00	$ 218.00	$ 225.00	
Travel	$ 250.00	$ 258.00	$ 266.00	$ 274.00	$ 282.00	
Low Income Sub-total	**$ 6,068.00**	**$ 5,431.76**	**$ 5,592.52**	**$ 5,753.28**	**$ 5,619.04**	
Education & Awareness						
Science Fair						
Host Science Fair - annual event						
Administration - investigate, organize and support - 120 hrs x $53	$ 6,360.00	$ 6,550.80	$ 6,741.60	$ 6,932.40	$ 7,123.20	
Premises rental	$ 600.00	$ 618.00	$ 637.00	$ 656.00	$ 675.00	
Catering etc	$ 500.00	$ 515.00	$ 530.00	$ 546.00	$ 563.00	
Materials	$ 1,000.00	$ 1,030.00	$ 1,061.00	$ 1,093.00	$ 1,126.00	
Publicity	$ 500.00	$ 515.00	$ 531.00	$ 547.00	$ 563.00	
Awards	$ 2,000.00	$ 2,250.00	$ 2,500.00	$ 2,750.00	$ 3,000.00	
Science Fair Sub-total	**$ 10,960.00**	**$ 11,478.80**	**$ 12,000.60**	**$ 12,524.40**	**$ 13,050.20**	
Trade / Event Show (s) Participation						
Attend trade shows / events to promote conservation programs and educate community						
Premises rental / fees $500 x 4	$ 2,000.00	$ 2,060.00	$ 2,120.00	$ 2,180.00	$ 2,240.00	
Travel $100 x 4	$ 400.00	$ 412.00	$ 424.00	$ 436.00	$ 448.00	
Labour ($1500 per event)	$ 6,000.00	$ 6,180.00	$ 6,360.00	$ 6,540.00	$ 6,720.00	
Material & Training	$ 2,800.00	$ 2,884.00	$ 2,968.00	$ 3,052.00	$ 3,136.00	
Trade Show / Event Sub-total	**$ 11,200.00**	**$ 11,536.00**	**$ 11,872.00**	**$ 12,208.00**	**$ 12,544.00**	

RC = Renewable Connection
SG = Smart Grid



CDM Program Budget

Activity	Year 1 - 2010	Year 2 - 2011	Year 3 - 2012	Year 4 - 2013	Year 5 - 2014
Estimating Note: Dollar values shown are 'then year'					
Annual inflation of 3% applied					
Estimating Detail - Level 3					
Website Upgrades					
Upgrade / update website to reflect programs and CDM information					
Develop & test content and functionality requirements / upgrades 80 hrs x $23.46	$ 1,876.80	$ 938.40	$ 966.55	$ 994.70	$ 1,022.86
Website upgrades- sub-contract 80hrs x $100	$ 8,000.00	$ 938.40	$ 966.55	$ 994.70	$ 1,022.86
Labour and Administration $23.46 x 8 x 12	$ 2,252.16	$ 2,319.72	$ 2,387.29	$ 2,454.85	$ 2,522.42
Website Maintenance 3hrs per month x $100	$ 3,600.00	$ 3,708.00	$ 3,816.00	$ 3,924.00	$ 4,032.00
Website Sub-total	**$ 15,728.96**	**$ 7,904.52**	**$ 8,136.39**	**$ 8,368.26**	**$ 8,600.13**
Residential					
Introduce CDM programs to assist the communities in consumption reduction and awareness					
Development, refinement and definition of Conservation Programs and Projects 300 hrs x $53	$ 15,900.00	$ 5,459.00	$ 5,618.00	$ 5,777.00	$ 5,936.00
Welcome Wagon - Material 800 cx X $4 per package	$ 4,000.00	$ 4,120.00	$ 4,240.00	$ 4,360.00	$ 4,480.00
Welcome Wagon - Maintenance & Administration ($23.46 x 4hrs x12 mths at 80% for residents)	$ 791.62	$ 815.36	$ 839.11	$ 862.86	$ 886.61
Welcome Wagon - Marketing & Distribution	$ 1,500.00	$ 1,545.00	$ 1,590.00	$ 1,635.00	$ 1,680.00
Residential - Sub-total	**$ 22,191.62**	**$ 11,939.36**	**$ 12,287.11**	**$ 12,634.86**	**$ 12,982.61**
Business / Industry Institutions and Associations					
Introduce CDM programs to assist the communities in consumption reduction and awareness					
Development, refinement and definition of Conservation Programs and Projects 300 hrs x $53	$ 15,900.00	$ 5,459.00	$ 5,618.00	$ 5,777.00	$ 5,936.00
Welcome Wagon - Material	$ 1,000.00	$ 1,030.00	$ 1,060.00	$ 1,090.00	$ 1,120.00
Welcome Wagon - Maintenance & Administration ($23.46 x 4hrs x12 mths at 20% for business)	$ 225.22	$ 231.97	$ 238.73	$ 245.49	$ 252.24
Welcome Wagon - Marketing	$ 1,500.00	$ 1,545.00	$ 1,590.00	$ 1,635.00	$ 1,680.00
Business - Sub-total	**$ 18,625.22**	**$ 8,265.97**	**$ 8,506.73**	**$ 8,747.49**	**$ 8,988.24**
Low Income & Seniors					
Introduce CDM programs to assist the communities in consumption reduction and awareness					
Development, refinement and definition of Conservation Programs and Projects 100 hrs x $53	$ 5,300.00	$ 1,801.47	$ 1,909.56	$ 1,963.60	$ 2,017.65
Labour (2 x 8 x 84 x $11)	$ 14,784.00	$ 15,227.52	$ 7,835.52	$ 8,057.28	$ 8,279.04
Training (Techincal / Program) 2 x 2 x $11 + 12 hrs @ $53.00	$ 988.00	$ 1,017.64	$ 1,047.28	$ 1,076.92	$ 1,106.56
Travel	$ 832.00	$ 856.96	$ 881.92	$ 906.88	$ 931.84
Material	$ 50,000.00	$ 50,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00
Low Income & Seniors Sub-total	**$ 71,904.00**	**$ 68,903.59**	**$ 21,674.28**	**$ 22,004.68**	**$ 22,335.09**
Community Communication					
Methods of communication to educate and promote CDM programs and create conservation awareness					
Newspaper	$ 7,500.00	$ 7,725.00	$ 7,950.00	$ 8,175.00	$ 8,400.00
Radio	$ 2,500.00	$ 2,575.00	$ 2,650.00	$ 2,725.00	$ 2,800.00
Transit	$ 1,400.00	$ 1,442.00	$ 1,484.00	$ 1,526.00	$ 1,568.00
Bill Messages / Inserts 4 bill inserts per year	$ 2,000.00	$ 2,060.00	$ 2,120.00	$ 2,180.00	$ 2,240.00
On Hold Phone Messages	$1,600	$ 1,648.00	$ 1,696.00	$ 1,744.00	$ 1,792.00
Bill envelope advertising (85,000 envelopes)	$ 1,500.00	$ 1,545.00	$ 1,590.00	$ 1,635.00	$ 1,680.00
Community Communication - Sub-total	**$ 16,500.00**	**$ 16,995.00**	**$ 17,490.00**	**$ 17,985.00**	**$ 18,480.00**
Conservation Fund					
This fund is to help assist Orangeville Hydro with adhoc CDM activities					
LDC Conservation Fund	$ 12,875.00	$ 13,647.50	$ 14,033.75	$ 14,420.00	$ 14,806.25
LDC Conservation Sub-total	**$ 12,875.00**	**$ 13,647.50**	**$ 14,033.75**	**$ 14,420.00**	**$ 14,806.25**

RC = Renewable Connection
SG = Smart Grid

CDM Program Budget

Estimating Note: Dollar values shown are 'then year'
Annual inflation of 3% applied

Estimating Detail - Level 3

Activity	Year 1 - 2010	Year 2 - 2011	Year 3 - 2012	Year 4 - 2013	Year 5 - 2014	
Resource Lending Library						
Note: Topics and subject matter held in the library: 'Green" building design, construction and renovation; systems design and installation; heating, cooling and ventilating; energy and conservation management and best practices, green power generation; green vehicles; green living- best practices. Sources. Engage in a 3 year incremental procurement program with low level acquisition in later years						
Books: 25 x $100.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 1,250.00	$ 1,250.00	
DVDs: 25 x $50	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 500.00	$ 500.00	
Periodicals and Magazines: 10 x $50	$ 500.00	$ 500.00	$ 500.00	$ 525.00	$ 525.00	
Technical Papers and Documents: 25 x $100	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 1,000.00	$ 1,000.00	
Directories: 4 x $100	$ 400.00	$ 400.00	$ 400.00	$ 200.00	$ 200.00	
Misc. materials	$ 250.00	$ 250.00	$ 250.00	$ 280.00	$ 290.00	
Advertising: pro-rated with other advertising	$ 500.00	$ 500.00	$ 500.00	$ 546.00	$ 563.00	
Operating expenses	$ 500.00	$ 515.00	$ 530.00	$ 546.00	$ 563.00	
Adminstrative labour: 50hrs x $53	$ 2,650.00	$ 2,730.00	$ 2,811.00	$ 2,895.00	$ 2,982.00	
Library sub-total	**$ 11,050.00**	**$ 11,145.00**	**$ 11,241.00**	**$ 7,742.00**	**$ 7,873.00**	
Green Energy Act - Staff Educating & Training						
Opportunities Pursuit and Capture						
Attending conferences/seminars etc.						
Labour 2 x 40 x $53	$ 4,240.00	$ 4,367.00	$ 4,498.00	$ 4,633.00	$ 4,633.00	
Labour 2 x 30 x $53	$ 3,180.00	$ 3,275.00	$ 3,373.00	$ 3,474.00	$ 3,578.00	
2 delegates x 2 Domestic	$ 5,000.00	$ 5,150.00	$ 5,305.00	$ 5,464.00	$ 5,628.00	
Labour 2 x 25 x $53	$ 2,650.00	$ 2,730.00	$ 2,812.00	$ 2,896.00	$ 2,983.00	
Public Relations	$ 3,000.00	$ 3,090.00	$ 3,183.00	$ 3,278.00	$ 3,377.00	
GEA Opportunities Pursuit Sub-total	**$ 18,070.00**	**$ 18,612.00**	**$ 19,171.00**	**$ 19,745.00**	**$ 20,199.00**	
FIT and microFIT Customer Assistance						
Pre and post implementation customer support						
Labour 20 hrs x 45wks x $53	$ 23,850.00	$ 49,140.00	$ 50,614.00	$ 52,133.00	$ 53,697.00	
Non-labour - travel	$ 2,000.00	$ 4,120.00	$ 4,244.00	$ 4,371.00	$ 4,502.00	
Software and tools	$ 2,000.00		$ 2,125.00		$ 2,250.00	
Training	$ 5,000.00		$ 5,300.00		$ 5,650.00	
FIT and MicroFIT Sub-total	**$ 32,850.00**	**$ 53,260.00**	**$ 62,283.00**	**$ 56,504.00**	**$ 66,099.00**	
Note: Estimate for installs, commisioning, post-install support contained in OH Estimates						
GRAND TOTAL	**$277,701.79**	**$266,693.95**	**$232,108.26**	**$227,250.29**	**$240,691.32**	**$ 1,244,445.62**
Management and Administration						
Labour 15% of labour component	$ 24,111.72	$ 22,107.22	$ 22,303.89	$ 22,135.26	$ 23,508.48	
Non-labour - pro-rated $ allocation:- 3%	$ 3,508.71	$ 3,579.37	$ 2,502.47	$ 2,390.46	$ 2,519.04	
Total	**$ 27,620.43**	**$ 25,686.60**	**$ 24,806.36**	**$ 24,525.72**	**$ 26,027.53**	
Summary						
Labour	$160,744.79	$147,381.49	$148,692.59	$147,568.41	$156,723.23	
Non Labour	$116,957.00	$119,312.46	$ 83,415.67	$ 79,681.88	$ 83,968.09	
OPA Funded Core Programs						
Orangeville Hydro would like to include these programs into our CDM budget should the OPA remove it from the slate of funded core programs after the 2009 season						
ERIP Program						**Total**
Fixed Funding	$ 36,191.00	$ 37,276.73	$ 38,362.46	$ 39,448.19	$ 40,533.92	
Variable Funding	$ 5,800.00	$ 6,300.00	$ 6,800.00	$ 6,800.00	$ 9,700.00	
ERIP Sub-total	**$ 41,991.00**	**$ 43,576.73**	**$ 45,162.46**	**$ 46,248.19**	**$ 50,233.92**	
PSB Program Execution						
Fixed Funding	$ 22,379.00	$ 23,050.37	$ 23,721.74	$ 24,393.11	$ 25,064.48	
Variable Funding	$ 22,715.00	$ 23,600.00	$ 25,075.00	$ 26,550.00	$ 28,025.00	
PSB Sub-total	**$ 45,094.00**	**$ 56,114.28**	**$ 57,702.42**	**$ 59,290.56**	**$ 60,878.70**	**$ 111,112.62**

Note: Orangeville Hydro is requesting these funds be provided on a quarterly basis