ORILLIAPOWER

Energizing Our Community

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September 16, 2009

Delivered by Courier

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

Dear Ms. Walli:

Re: Orillia Power Distribution Corporation - Board File No: EB-2009-0273
2010 Electricity Distribution (Cost of Service) Rate Application

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

This Application is filed in accordance with the Ontario Energy Board (the "Board") Filing Requirements for Transmission and Distribution Applications Chapter 2 issued May 27, 2009 and Chapter 3 issued July 22, 2009.

Two hard copies of the Application are enclosed. Electronic copies of the Application in PDF format and required models in Excel format have been submitted through the Board's Regulatory Electronic Submission System ("RESS"). A paper copy of the online confirmation and the RESS submission reference number will be enclosed.

A CD with copies of the Application in PDF format and the required Excel models has been included within each hard copy binder.

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This Application is respectfully submitted for the Board's consideration. If you have any questions, please contact Pat Hurley at (705)326-2495 ext 222 or phurley@orilliapower.ca.

Respectfully,

John F. Mattinson P. Eng.
President & Secretary
Orillia Power Distribution Corporation

ORILLIA POWER DISTRIBUTION Corporation

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES (EDR) EFFECTIVE MAY 1, 2010

Application Identification

Orillia Power Distribution Corporation

ED-2002-0530

2010 Rates Rebasing Application

EB-2009-0273

Filed with the Board: September 16, 2009

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

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OPDC APPLICATION EXHIBITS

EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

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EXHIBIT 1 - TABLES

EXHIBIT 1 - APPENDICES

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

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EXHIBIT 2 - RATE BASE

Schedule No.

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)
2010 ELECTRICITY DISTRIBUTION RATES APPLICATION
EB-2009-0273
EFFECTIVE MAY 1, 2010

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EXHIBIT 2 - TABLES

EXHIBIT 2 - APPENDICES

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

EXHIBIT 3 - OPERATING REVENUE

EXHIBIT 3 - TABLES

EXHIBIT 3 - TABLES (continued)

EXHIBIT 3 - APPENDICES

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)
2010 ELECTRICITY DISTRIBUTION RATES APPLICATION
EB-2009-0273
EFFECTIVE MAY 1, 2010

EXHIBIT 4 - OPERATING COSTS

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

EXHIBIT 4 - TABLES

EXHIBIT 4 - TABLES (continued)

EXHIBIT 4 - APPENDICES

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE

EXHIBIT 5 - TABLES

EXHIBIT 5 - APPENDICES

EXHIBIT 6 - CALCULATION OF REVENUE DEFICIENCY

EXHIBIT 6 - TABLES

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

EXHIBIT 7 - COST ALLOCATION

Schedule No.

EXHIBIT 7 - TABLES

EXHIBIT 7 - APPENDICES

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

EXHIBIT 8 - RATE DESIGN

Schedule No.

EXHIBIT 8 - TABLES

EXHIBIT 8 - TABLES (continued)

EXHIBIT 8 - GRAPHS

EXHIBIT 8 - APPENDICES

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS

Schedule No.

EXHIBIT 9 - TABLES

EXHIBIT 9 - APPENDICES

EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

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EXHIBIT 1 - TABLES

EXHIBIT 1 - APPENDICES

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 Orillia Power Distribution Corporation to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2010.

Title of Proceeding:	An application by **ORILLIA POWER DISTRIBUTION CORPORATION** for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2010.
Applicant's Name:	**ORILLIA POWER DISTRIBUTION CORPORATION**
Applicant's Address:	360 West Street South PO Box 398 Orillia, ON L3V 6J9
	Attention: John F. Mattinson, P.Eng., President & Secretary Telephone: (705) 326-2495 Ext. 225 Fax: (705) 326-0800
E-mail:	jmattinson@orilliapower.ca

APPLICATION

Introduction:

The Applicant is Orillia Power Distribution Corporation (referred to in this Application as the “Applicant”, “Orillia Power” or “OPDC”). The Applicant is incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the City of Orillia.

The Applicant carries on the business of distributing electricity within the City of Orillia. A copy of Orillia Power Distribution Corporation’s Electricity Distribution Licence (ED-2002-0530 issued on June 3, 2003) accompanies this Schedule as Appendix 1-A.

The Applicant hereby applies to the Ontario Energy Board (the “OEB”) pursuant to Section 78 of the Ontario Energy Board Act, 1998 (the “OEB Act”) for approval of its proposed distribution rates and other charges, effective May 1, 2010.

A list of requested approvals is set out in Exhibit 1, Tab 1, Schedule 3.

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

Application Reviewed by OPC’s Audit Committee:

This rate application has been reviewed in its entirety by Orillia Power’s audit committee. The audit committee consisting of two Chartered Accountants and a Professional Engineer has recommended to the OPDC Board of Directors that this rate application be submitted to the OEB for approval. The OPDC Board has accepted the recommendation of the audit committee and passed resolution OPDC-2009-09-09-1 approving the submission of this application to the Ontario Energy Board.

Proposed Distribution Rates and Other Charges:

The Schedule of Rates and Charges proposed in this Application has been identified in Table 1-1 attached to this summary and Table 8-17 of Exhibit 8, Tab 5, Schedule 2. The material being filed in support of this Application sets out Orillia Power Distribution Corporation's approach to its distribution rates and charges.

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.

The Proposed Distribution Rates and Other Charges are Just and Reasonable:

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

- the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;
- the proposed adjusted rates are necessary to meet the Applicant's Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILs") requirements;
- there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures;
- the other service charges proposed by the Applicant are the same as those previously approved by the OEB; and
- such other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought:

The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges as set out in Table 1-1 attached to this summary and Table 8-17 of Exhibit 8, Tab 5, Schedule 2 of 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.

Form of Hearing Requested:

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

DATED at Orillia, Ontario, this 16'Th day of September 2009.

All of which is respectfully submitted,
FOR ORILLIA POWER DISTRIBUTION CORPORATION

John F. Mattinson P.Eng. President & Secretary	Patrick J. Hurley B.Math., CMA Treasurer

Table 1-1 Part 1: SCHEDULE OF PROPOSED RATES AND CHARGES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
RESIDENTIAL		
Service Charge	$	15.41
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0140
Low Voltage Cost Recovery	$/kWh	0.0006
Regulatory Asset Rider (One Year)	$/kWh	(0.0013)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035
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	$	35.56
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0158
Low Voltage Cost Recovery	$/kWh	0.0006
Regulatory Asset Rider (One Year)	$/kWh	(0.0011)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
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	$	375.23
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	3.4259
Low Voltage Cost Recovery	$/kW	0.2262
Regulatory Asset Rider (One Year)	$/kW	(0.5841)
Retail Transmission Rate – Network Service Rate	$/kW	1.4236
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2955
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
STANDBY POWER		
Distribution Volumetric Rate - $ per kW of nameplate capacity (per month)	$/kW	1.0110

Table 1-1 Part 1 (continued): SCHEDULE OF PROPOSED RATES AND CHARGES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
UNMETERED SCATTERED LOAD		
Service Charge (per connection)	$	8.31
Distribution Volumetric Rate	$/kWh	0.0074
Low Voltage Cost Recovery	$/kWh	0.0006
Regulatory Asset Rider (One Year)	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
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)	$	3.68
Distribution Volumetric Rate	$/kW	9.6553
Low Voltage Cost Recovery	$/kW	0.1722
Regulatory Asset Rider (One Year)	$/kW	(0.5318)
Retail Transmission Rate – Network Service Rate	$/kW	1.0541
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9862
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)	$	2.77
Distribution Volumetric Rate	$/kW	9.1870
Low Voltage Cost Recovery	$/kW	0.1686
Regulatory Asset Rider (One Year)	$/kW	(0.2590)
Retail Transmission Rate – Network Service Rate	$/kW	1.0487
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9659
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Table 1-1 Part 2: SCHEDULE OF PROPOSED SPECIFIC SERVICE CHARGES AND ALLOWANCES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
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
Other		
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1000.00
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 -transformer losses - applied to measured demand and ene and energy	%	(1.00)

Table 1-1 Part 3: SCHEDULE OF PROPOSED RETAIL SERVICE CHARGES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
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

Table 1-1 Part 4: SCHEDULE OF PROPOSED LOSS FACTORS

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
LOSS FACTORS		
Total Loss Factor - Secondary Metered Customer < 5,000 kW		1.0593
Total Loss Factor - Secondary Metered Customer > 5,000 kW		N/A
Total Loss Factor - Primary Metered Customer < 5,000 kW		1.0487
Total Loss Factor - Primary Metered Customer > 5,000 kW		N/A

CONTACT INFORMATION

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L3V 6J9
Main Telephone: (705) 326-7315
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APPLICANT'S RATES CONSULTANT:
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Telephone: (416) 825-4144
E-mail: bbacon@blgcanada.com

SPECIFIC APPROVALS REQUESTED

In this proceeding, Orillia Power Distribution Corporation is requesting the following approvals:

- Approval to charge rates effective May 1, 2010 to recover a revenue requirement of $7,658,200, which includes an existing revenue deficiency of $955,200, as set out in Exhibit 6, Tab 1, Schedule 1, Table 6-1. The schedule of proposed rates is set out in Exhibit 1, Tab 1, Schedule 1, Table 1-1 and Exhibit 8, Tab 5, Schedule 2, Table 8-17.

- 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 1, Table 5-1 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 factors for 2010 as set out in Exhibit 8, Tab 4, Schedule 1, Table 8-12;

- Approval to continue to charge the same Retail Transmission-Network Service, Retail Transmission-Connection, and Wholesale Market and Rural Rate Protection Charges as were approved in the OEB Decision and Order in the matter of OPDC's 2009 Distribution Rates (EB-2008-0239) subject to any modifications as a result of the OEB's Decision and Rate Order in the EB-2008-0272 proceeding approving new Uniform Transmission Rates, effective July 1, 2009;

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of OPDC's 2009 Distribution Rates (EB-2008-0239) and

- Approval to dispose of the following Deferral and Variance Account Balances, as at December 31, 2008 plus interest to April 30, 2010, over a one-year period using the method of recovery described in Exhibit 9, Tab 1, Schedule 2 and Appendix 9-B:

1508	Other Regulatory Assets
1518	Retail Cost Variance Account – Retail
1548	Retail Cost Variance Account – STR
1550	Low Voltage Variance Account
1580	Retail Settlement Variance Account - Wholesale Market Service
1584	Retail Settlement Variance Account - Retail Transmission Network
1586	Retail Settlement Variance Account - Retail Transmission Connection
1588	Retail Settlement Variance Account – Power
1588	Retail Settlement Variance Account - Power, Sub-account Global Adjustments

DESCRIPTION OF OPDC'S OPERATING ENVIRONMENT

General Description:

Orillia Power Distribution Corporation operates its distribution system within a licensed territory of 27 square kilometers within the City of Orillia. The City of Orillia (population 31,000) is located 125 km north of Toronto on the shores of Lake Couchiching and Lake Simcoe.

Orillia Power Distribution services approximately 12,800 customers within an urban environment. As of January 1, 2009, OPDC had approximately 245 kilometres of overhead circuits, 58 kilometres of underground circuits and 1,756 transformers operating within the system.

OPDC takes power from Hydro One's Orillia Transformer Station at 44kv (4 feeders: M1, M4, M7 & M8) and steps power down to its distribution voltages of 13.8kV and 4.16kV using 10 distribution stations (4 at13.8kV and 6 at 4.16kV).

A map of OPDC's Distribution Service Territory is attached as Appendix 1-B. A schematic diagram of OPDC's distribution system is attached in Appendix 1-C.

Neighbouring Utilities:

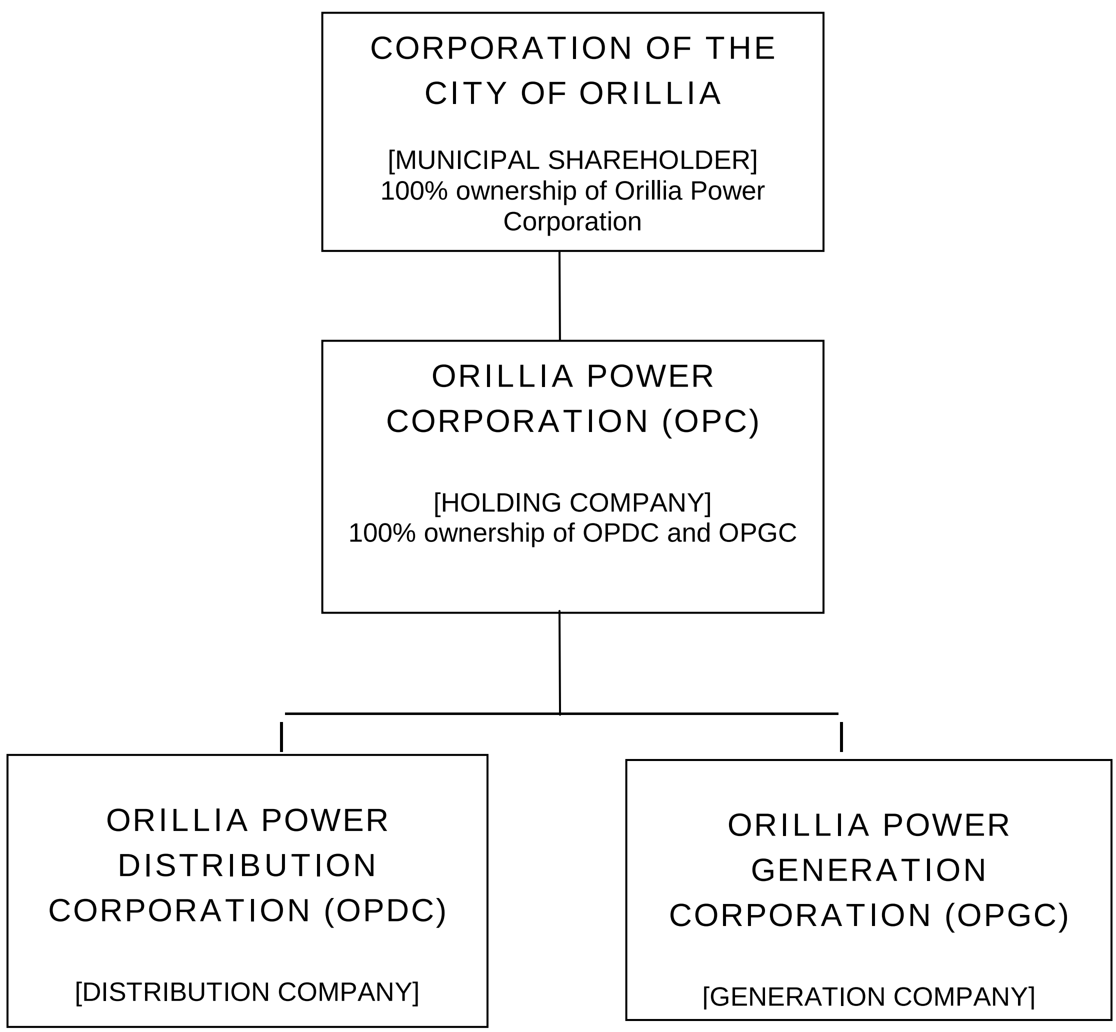
Orillia Power Distribution is completely embedded within Hydro One's service territory. There are no distribution utilities embedded within Orillia Power's system for which Orillia Power acts as host.

UTILITY ORGANIZATIONAL STRUCTURE

Ownership Structure:

Orillia Power Distribution Corporation (OPDC) is a 100% wholly-owned subsidiary of Orillia Power Corporation (OPC), which in turn is 100% wholly owned by the City of Orillia. Orillia Power Corporation also has 100% ownership in Orillia Power Generation Corporation (OPGC). Key Ownership relationships are displayed in the chart below.

CORPORATE ENTITIES RELATIONSHIP CHART



UTILITY ORGANIZATIONAL STRUCTURE (continued)

Parent Company Board Representation on OPDC Board:

Orillia Power Corporation has six Board members, two of whom serve on the Orillia Power Distribution Corporation Board. OPDC has a total of three Board members, one of whom is independent of all other affiliates. The Board currently meets at least 10 times each year.

Qualification of Directors:

OPC and its subsidiary companies are required to comply with the City of Orillia Shareholder Declaration and Direction established when the companies were incorporated in 2000 under Bill 35. This declaration establishes the qualifications and skill set required to sit on the OPC Board and its subsidiaries.

The required mix of skills include experience in corporate governance, corporate financial structures and transactions, competitive market development, regulatory environments, finance and accounting, taxation, treasury, corporate law, health and safety and private sector business. The highly qualified, professionally designated and very experienced Board of Orillia Power and its subsidiaries bring this skill set and more to every meeting.

The shareholder declaration also states that City Councilors and City staff are prevented from sitting on OPC's Board or its subsidiaries. We believe that this restriction establishes an appropriate level of Board independence from its municipally owned shareholder.

Senior Management Reporting Relationships Among OPC, OPDC and OPGC:

The President & Secretary and the Treasurer (CFO) of OPDC act in the same capacity for both Orillia Power Corporation and Orillia Power Generation Corporation. The President & Secretary also serves as the sole director of OPGC.

Shared Services and Affiliate Relationships Code Exemptions:

In order to reduce overall distribution costs, OPDC and OPGC share some administrative and technical services among the two corporations. The corporations are guided by a shared services agreement attached in Appendix 1-E. Orillia Power has applied for and received certain exemptions from the Affiliate Relationships Code (ARC) attached in Appendix 1-F.

Services provided by OPDC to OPGC are documented in detail in section 1.01 of the agreement and services provided by OPGC to OPDC are documented in detail in section 1.02 of the agreement.

Planned changes in Corporate and / or Operational Structure:

No changes to OPDC’s corporate and operational structures are planned at the present time.

OTHER ADMINISTRATIVE MATTERS

Proposed Issues List:

OPDC believes that the OEB filing requirements and guidelines have been followed in preparing this application. It is OPDC's opinion that there may be the following issues related to this application:

- The reasonableness of the 2010 capital program.
- The reasonableness of the 2010 operating, maintenance and administrative budget.
- The reasonableness of the 2010 weather normalized forecast.
- The reasonableness of the 2010 proposed revenue requirement.

Accounting Orders and List of Non-Compliance with USofA:

OPDC is not requesting Accounting Orders in this proceeding. OPDC 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.

Status of Board Directives From Previous Decisions:

Orillia Power Distribution Corporation has no Board Directives at this time.

List of Witnesses and Their Curriculum Vitae:

Orillia Power Distribution Limited is requesting that this application be disposed of by way of a written hearing. In the event that OPDC is notified that an oral hearing will be necessary, a list of witnesses and their Curriculum Vitae will be supplied at that time.

ORILLIA POWER'S MISSION & VISION AND CORE VALUES

Orillia Power mission and vision statement as well as our core values (signed by Board and staff) follow on the next two pages. Orillia Power employees are guided in their decision making processes by these statements and values. We believe that these statements and values provide a roadmap to follow in our interactions with all parties and stakeholders both inside and outside of the company.

An electricity distribution company licensed by the Ontario Energy Board, Orillia Power Distribution Corporation's mission is to "deliver energy cost-effectively to our customers, the citizens of Orillia". As stated in our mission, OPDC's priorities are:

- The safety, professional development and well-being of our staff.
- Maintenance of the highest standards for public safety, reliability of supply and protection of the environment.
- First class customer service.
- The creation of value for our shareholder while ensuring the long term growth and stability of our organization
- Have a positive economic impact for the betterment of the City of Orillia and its citizens.

Orillia Power employee actions are always guided by our core values which are:

- Belief in all employees	Good communication	Fair treatment to all
- Freedom to operate	Openness & honesty	Partnerships
- Relationships & trust	Respect	Humour

We believe that we are achieving our mission and core values as will be demonstrated throughout this application.

MISSION & VISION

Orillia Power's MISSION is to efficiently generate environmentally-friendly energy and to deliver energy cost-effectively to our customers, the citizens of Orillia.

While pursuing this mission, Orillia Power will:

- *Contribute to the safety, professional development and well-being of our staff;*
- *Maintain highest standards for public safety, reliability of supply and protection of the environment;*
- *Consistently provide first-class customer service in an efficient and professional manner;*
- *Create value for our shareholder and ensure the long-term growth and stability of the organization;*
- *Have a positive impact on the economic development and betterment of our community.*

Our VISION: A highly skilled and enthusiastic workforce, striving to achieve our full potential in renewable power generation and energy distribution.

ORILLIAPOWER

Energizing Our Community

OUR CORE VALUES

BELIEF IN ALL EMPLOYEES

GOOD COMMUNICATION

FAIR TREATMENT TO ALL

FREEDOM TO OPERATE

OPENNESS & HONESTY

PARTNERSHIPS

RELATIONSHIPS

RESPECT

TRUST

HUMOUR

Orillia Power

MARCH 30, 2007

SUMMARY OF THE APPLICATION (PURPOSE, NEED AND TIMING)

Purpose of Application:

Since 1913, employees of Orillia Water, Light & Power Commission (prior to Bill 35) and Orillia Power have successfully met the objectives of our mission statement as outlined in Schedule 1. Management and staff have every intention of continuing to successfully meet our Corporate Mission and Vision moving into the future.

Living up to our mission statement means that OPDC Board and staff must enhance the quality, safety, and reliability of our electrical distribution system while meeting or exceeding all statutory, environmental and regulatory requirements. We are required to properly and prudently manage all of our assets and resources in order to maintain or preferably improve the viability of OPDC while achieving a balance of stakeholder objectives.

Corporate objectives include ensuring OPDC provides a safe, proactive work environment that employees are proud to be part of, while pursuing their career objectives. They also include providing first class customer service in an environment that is constantly shifting. All of these objectives must be achieved while pursuing a customer and community focused path that enhances the overall value of the organization to the Shareholder balanced against reasonable electricity distribution rates.

Orillia Power Distribution Corporation has submitted this application to the Ontario Energy Board for increased distribution rates to become effective May 1, 2010 in order to ensure that our ability to achieve all of the objectives summarized above and the many accomplishments on safety, customer service and reliability listed throughout this application will not be compromised in any way due to the lack of adequate financial resources.

Need of Application:

Orillia Power Distribution Corporation's requested revenue requirement for 2010 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 deemed by the Ontario Energy Board, as it transitions to a 60%/40% debt equity ratio by 2010. Through this rate application, OPDC seeks the recovery through rates and other charges of its proposed 2010 total revenue requirement in the amount of $7,658,200.

When forecasted energy and demand levels for 2010 are considered, OPDC has calculated that if distribution rates remained as is for 2010, it would have a revenue deficiency of $955,200 before taxes and $671,200 after taxes. Excluded from this estimate is any impact of energy costs. This calculation is included in Exhibit 1, Tab 2, Schedule 6 as well as Exhibit 6, Tab 1, Schedule 1. The increase in rates requested enables OPDC to achieve deemed net earnings of $664,600 for a deemed return on equity of 8.01%.

OPDC 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. OPDC understands and accepts that these parameters will likely be revised by the OEB for 2010 rates based on January 2010 market interest rate information.

Since 2003, OPDC has experienced declining revenues while working in a regulatory environment that has been constantly changing. As will be demonstrated in Exhibit 4, OPDC has been faced with increased costs due to the changing and increased regulatory expectations coming from many different government agencies and the government itself. Between 2003 and 2009, OPDC's core distribution rates, through the various annual rate adjustment mechanisms, have been adjusted downwards by 11.7%. Appendix 3-C provides calculations of rate impacts.

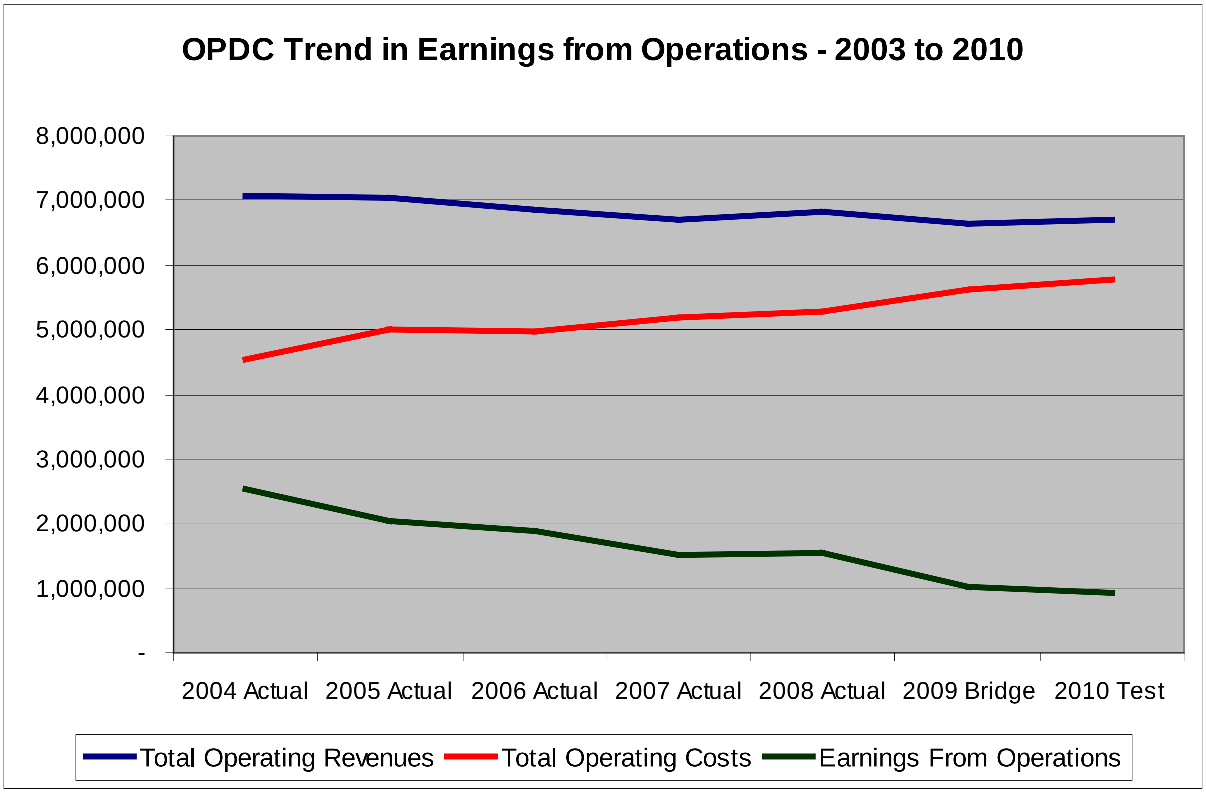
Declining revenues from rate adjustments and increasing costs year after year have lead to declining earnings from operations. Table 1-2 summarizes total operating revenues and operating costs and earnings from operations for 2003 to the 2010 Test year assuming rates are not rebased. Cumulatively, OPDC will have experienced a 9% decrease in total (includes other) revenues and a 28% increase in costs from 2003 to 2010 and earnings from operations has declined by two thirds or 67% in seven years.

Table 1-2: Earnings From Operations - 2003 to 2010 Under Status Quo - No Rate Rebasing

Description	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
REVENUES								
Distribution Revenues	6,979,000	6,763,000	6,667,000	6,387,000	6,201,000	6,241,000	6,178,000	6,208,000
Other Operating Revenues	350,000	309,000	376,000	482,000	498,000	600,000	460,000	485,000
Total Operating Revenues	**7,329,000**	**7,072,000**	**7,043,000**	**6,869,000**	**6,699,000**	**6,841,000**	**6,638,000**	**6,693,000**
DISTRIBUTION COSTS								
O M & A Expenditures	3,211,000	3,275,000	3,777,000	3,616,000	3,857,000	3,878,000	4,185,000	4,311,000
Depreciation & Amortization	1,306,000	1,265,000	1,240,000	1,359,000	1,320,000	1,409,000	1,431,000	1,450,000
Total Operating Costs	**4,517,000**	**4,540,000**	**5,017,000**	**4,975,000**	**5,177,000**	**5,287,000**	**5,616,000**	**5,761,000**
Earnings From Operations	**2,812,000**	**2,532,000**	**2,026,000**	**1,894,000**	**1,522,000**	**1,554,000**	**1,022,000**	**932,000**

PERCENTAGE CHANGES YEAR OVER YEAR AND CUMULATIVE FROM 2003							
Total Operating Revenues - Year Over Year	-4%	0%	-2%	-2%	2%	-3%	1%
Operating Revenues - **Cumulative from 2003**	**-4%**	**-4%**	**-6%**	**-9%**	**-7%**	**-9%**	**-9%**
Total Operating Costs - Year Over Year	1%	11%	-1%	4%	2%	6%	3%
Operating Costs - **Cumulative from 2003**	**1%**	**11%**	**10%**	**15%**	**17%**	**24%**	**28%**
Earnings From Operations - Year Over Year	-10%	-20%	-7%	-20%	2%	-34%	-9%
Earnings From Operations - **Cumulative 2003**	**-10%**	**-28%**	**-33%**	**-46%**	**-45%**	**-64%**	**-67%**

Table 1-2 is demonstrated graphically in the chart that follows:



Earnings from operations does not include other significant costs such as interest on long term debt and income taxes which need to be paid prior to determining net earnings for the year as shown in Table 1-11 (Ex.1 Tab 3 Sch. 1). Maintaining the status quo in rates will result in deteriorating actual returns on equity in 2009, 2010 and beyond. These returns are well below levels currently approved by the OEB as Table 1-3 clearly illustrates. This table below is an excerpt from OPDC's projection of Financial Results if status quo is maintained (no rebasing) for the period from 2007 through to 2013 filed in Appendix 1-G. These going forward rates of return jeopardize OPDC's ability to continue achieving our mandate, and maintain financial stability and system reliability, and are not in any of our stakeholders' long run best interests.

Table 1-3: Returns on Equity for 2007 to 2013 Under Status Quo - No Rate Rebasing

Description	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2011 Projection	2012 Projection	2013 Projection
RETURN ON EQUITY - OPDC							
Return on Equity - OPDC	**5.7%**	**6.6%**	**3.9%**	**3.0%**	**1.5%**	**0.6%**	**-0.9%**

Increased rates are required to ensure that OPDC is able to maintain proper infrastructure investment ensuring a continued safe and reliable distribution system for our customers and our staff while still providing a reasonable return on investment to our municipal shareholder. OPDC must make a significant dollar investment in capital projects into (1) currently unserviced areas and (2) distribution system upgrades needed in existing areas.

Table 1-4 outlines the cost of capital projects that will require completion in this and the next four years in order to maintain and enhance our distribution system to improve reliability and safety. Funding for these projects will be jeopardized should proposed rates not be approved. A detailed breakdown of OPDC's capital expenditure plans out to 2015 is listed in Appendix 1-H. These capital plans must be achieved in addition to OPDC's investment in smart metering infrastructure.

Table 1-4: Capital Expenditures Completed and Planned from 2007 to 2013 for OPDC

Description	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2011 Projection	2012 Projection	2013 Projection
CAPITAL EXPENDITURES - OPDC							
Capital Expenditures - OPDC	**$1,157,000**	**$2,252,000**	**$1,946,000**	**$1,714,000**	**$2,561,000**	**$1,983,000**	**$1,778,000**

Since the implementation of Bill 35, distribution companies have been required to quickly respond to many different provincially mandated energy sector initiatives. OPDC needs to ensure that we provide our staff with adequate resources and skills training to properly cope with these initiatives.

OPDC needs to manage staffing levels and skills to ensure regulatory compliance (OEB, ESA), promote conservation and other government programs, implement smart meter infrastructure and respond to financial reporting changes resulting from the adoption of International Financial Reporting Standards (IFRS). OPDC has been required to add staff in both engineering and finance to ensure that we comply with all of the various regulations.

OPDC has many accomplishments to be proud of including our results on safety, reliability and customer service outlined below. OPDC plans to continue our excellent record in these areas. OPDC recognizes and is concerned that lack of adequate financial resources could impair our ability do so.

The health and safety of our workforce is Orillia Power's first priority. A recent article in September 2009 ZeroQuest Magazine "Orillia Power Creates New Rack Design" illustrates our constant focus on safety. This article is attached in this Exhibit as Appendix 1-K. Orillia Power has operated **over six and a half years consecutively to the date of this application without a lost time injury**. OPDC is participating in E&USA's ZeroQuest program and has recently achieved the Silver Level. This program promotes a vision of zero lost-time injuries and requires that we use best practices in all areas of safety.

OPDC has been an active partner in the development of the first portable children's safety village in Canada. This is a non-profit organization that provides safety training including electricity safety training to hundreds of local school children each year. These achievements and initiatives take significant effort, time and financial resources. Orillia Power is very proud of our success in this area.

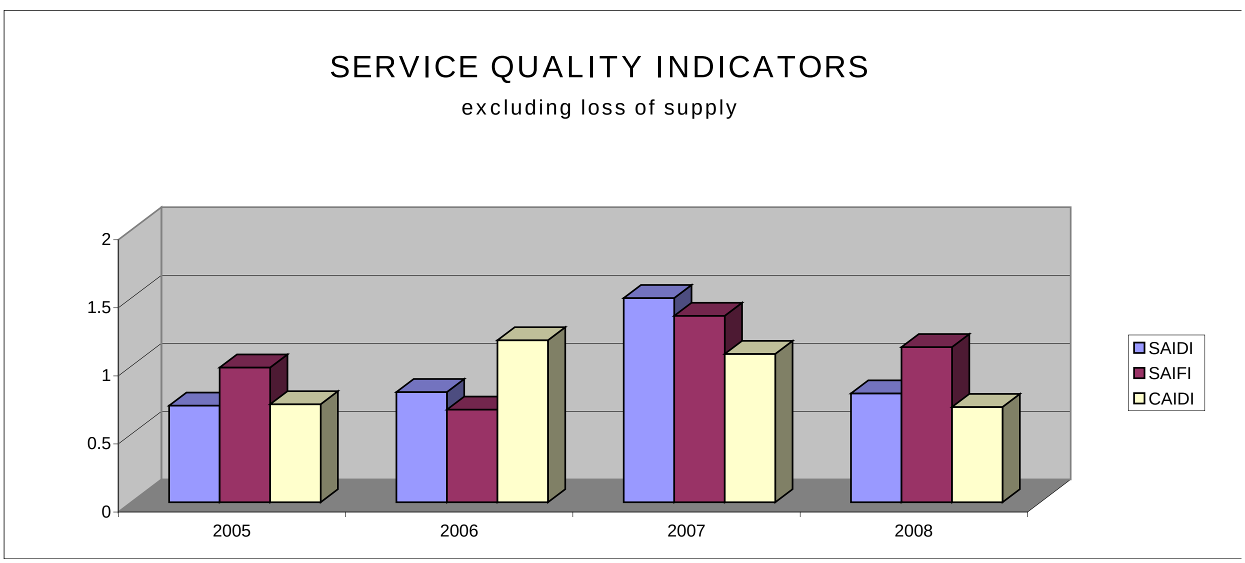
OPDC has consistently exceeded the OEB's Service Quality Indicators for customer service as set out in Table 1-5 below. OPDC has annually targeted to maintain its performance at levels above the OEB standards. OPDC maintains its infrastructure in order to enhance reliability as evidenced by the good system reliability indicators excluding loss of supply (2) indicated in Table 1-6.

Table 1-5: Service Quality Indicators 2005 to 2008 - CUSTOMER SERVICE

Customer Service	Minimum Standards	2005	2006	2007	2008
Connection New Services - Low Voltage within 5 working days	90% or better	100.00	100.00	100.00	100.00
Connection New Services - High Voltage within 10 working days	90% or better	N/A	N/A	N/A	N/A
Underground Cable Locates - within 5 working days	90% or better	100.00	100.00	100.00	100.00
Appointments Met - at the appointed time	90% or better	100.00	100.00	100.00	100.00
Telephone Accessibility - answered in person within 30 seconds	65% or better	96.75	100.00	98.10	98.50
Written Response to Inquiries - within 10 working days	80% or better	N/A	N/A	100.00	100.00
Emergency Response - Urban within 60 minutes	80% or better	100.00	100.00	100.00	100.00
Emergency Response - Rural within 120 minutes	80% or better	N/A	N/A	N/A	N/A

Table 1-6: Service Quality Indicators 2005 to 2008 - RELIABILITY

Reliability	Minimum Standards	2005	2006	2007	2008
Service Quality - (1) All Interruptions:					
SAIDI - System Average Interruption Duration Index (Hours per Customer)	Compared to previous 3 yrs	1.57	1.65	5.36	1.69
SAIFI - System Average Interruption Duration Index (Interruptions per Customer)	Compared to previous 3 yrs	1.63	1.62	3.60	2.27
CAIDI - System Average Interruption Duration Index (Hours per Interruption)	Compared to previous 3 yrs	0.97	1.02	1.49	0.74
Service Quality - (2) All Interruptions excluding loss of supply (Cause Code 2):					
SAIDI - System Average Interruption Duration Index (Hours per Customer)	Compared to previous 3 yrs	0.71	0.81	1.50	0.80
SAIFI - System Average Interruption Duration Index (Interruptions per Customer)	Compared to previous 3 yrs	0.99	0.68	1.37	1.14
CAIDI - System Average Interruption Duration Index (Hours per Interruption)	Compared to previous 3 yrs	0.72	1.19	1.09	0.70



		Units of Measure
SAIDI	"System Average Interruption Duration Index"	Hours per Customer
SAIFI	"System Average Interruption Frequency Index"	Interruptions per Customer
CAIDI	"Customer Average Interruption Duration Index"	Hours per Interruption

OPDC intends to maintain or enhance the standards achieved to date in all areas of customer service and reliability. In order to do so OPDC will need to continue making capital investments in infrastructure over the next two years at levels which were expended in 2008.

In light of all of the aforementioned considerations, Orillia Power Distribution Corporation 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 1 Table 1-1 and Exhibit 8, Tab 5, Schedule 2 Table 8-17 to this Application. Approval of these rates will restore OPDC's return on equity to levels approximating the approved cost of capital parameters as can be seen in Table 1-7 and Appendix 1-I.

Table 1-7: Returns on Equity for 2007 to 2013 Including Impacts of Rate Rebasing

Description	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2011 Projection	2012 Projection	2013 Projection
RETURN ON EQUITY - OPDC							
Return on Equity - OPDC	5.7%	6.6%	3.7%	6.7%	8.8%	7.9%	6.7%

Timing of Application:

Orillia Power Distribution Corporation is requesting a rate change to be effective May 1, 2010.

Financial information included in this application includes OEB-Approved data for 2006, audited financial results information for 2006 through 2008 and projected financial results for 2009 (“2009 Bridge Year”). Financial information supporting the calculation of rates in this Application is a forecast of results for OPDC’s fiscal year ending December 31, 2010 (the “2010 Test Year”). The 2010 Test Year information has been used to set rates for the period May 1, 2010 to April 30, 2011.

The OPDC Board of Directors has approved the 2010 distribution capital and operations expenditures budget submitted with this application.

The Test Year revenue requirement forecast is needed by OPDC to restore its ability to earn the returns approximating the maximum permitted by the OEB. For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board’s Decision must be effective for volumes consumed on and after May 1, 2010.

SUMMARY OF CUSTOMER BILL IMPACTS FROM RATE REBASING IN 2010

In preparing this application, OPDC has considered the impacts on its customers, with the goal of minimizing those impacts as much as possible. With respect to cost allocation, Table 7-3 in Exhibit 7 shows that for the majority of OPDC customers, the current revenue to cost ratio of each rate class currently falls within the applicable thresholds defined by the OEB in the November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors. The only exception is the street lighting class and mitigation measures are discussed below for that class.

Customer Rate Impacts:

Table 1-8 highlights the increases for a typical residential and small general service customer. The rate increases proposed will increase the total monthly bill of an 800 kWh per month residential customer by $3.82 or 4.3%. The total monthly bill of a 2000 kWh per month less than 50 kW general service customer will increase $10.25 or 4.5%.

Table 1-8: Rate Increases Proposed for Typical Residential and Small General Service Customers

Description	Increase in Total Bill	% Increase in Total Bill
Residential - 800 kWh per month	**$3.82**	**4.3%**
General Service Less Than 50 kW - 2000 kWh per month	**$10.25**	**4.5%**

Table 1-9 below outlines rate impacts for all major classes of OPDC customers due to revised distribution rates, loss factors and repayment of deferral and variance account balances over one year. All of the rate impacts with the exception of street lighting are within reasonable levels and do not require rate mitigation. OPDC has attempted to lower total bill impact for all classes by repaying certain deferral and variance accounts over the shortest possible time period being one year.

Cost Allocation Thresholds and Rate Impacts on Street Lighting:

OPDC understands that the street lighting increases are significant, and will be seen so by our street lighting customer (City of Orillia), but we are aware of the direction given by the OEB in other rate proceedings under similar circumstances. OPDC's updated cost allocation study has indicated that street light revenues are significantly under contributing to their allocated costs.

OPDC has proceeded to close the gap towards the lower threshold of the approved range as required in other Board decisions on 2008 and 2009 applications for our 2010 rate application. The street light class rates are being increased by approximately 50% of the difference between their current levels and the lower threshold of the OEB's range. It is proposed that further adjustments to the revenue–to–cost ratios for street lights be made in 2011 and 2012 in order to reach the lower threshold of the approved range. Increased revenue from this class will be offset by reductions in distribution revenue from the General Service Over 50 kW class.

In an effort to help our municipality mitigate the higher street lighting costs they will be faced with, OPDC has been working with them to evaluate lower energy consuming fixtures such as LED type.

Table 1-9: SUMMARY Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

RESIDENTIAL

VOLUMES	Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
100	$15.62	$17.74	$2.12	$23.48	$25.73	$2.25	13.6%	9.0%	9.6%
250	$17.54	$19.73	$2.19	$37.10	$39.73	$2.63	12.5%	5.9%	7.1%
500	$20.74	$23.06	$2.32	$59.93	$63.04	$3.11	11.2%	3.9%	5.2%
800	**$24.58**	**$27.05**	**$2.47**	**$89.34**	**$93.16**	**$3.82**	**10.0%**	**2.8%**	**4.3%**
1,000	$27.14	$29.71	$2.57	$109.39	$113.71	$4.32	9.5%	2.3%	3.9%
1,500	$33.54	$36.36	$2.82	$159.66	$165.11	$5.45	8.4%	1.8%	3.4%
2,000	$39.94	$43.02	$3.08	$209.84	$216.51	$6.67	7.7%	1.5%	3.2%

GENERAL SERVICE LESS THAN 50 KW

VOLUMES	Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
1,000	$46.19	$51.92	$5.73	$126.26	$133.72	$7.46	12.4%	4.5%	5.9%
2,000	**$60.59**	**$67.29**	**$6.70**	**$227.48**	**$237.73**	**$10.25**	**11.1%**	**2.9%**	**4.5%**
3,000	$74.99	$82.65	$7.66	$328.72	$341.67	$12.95	10.2%	2.3%	3.9%
5,000	$103.79	$113.38	$9.59	$531.15	$549.59	$18.44	9.2%	1.8%	3.5%
10,000	$175.79	$190.21	$14.42	$1,037.27	$1,069.31	$32.04	8.2%	1.4%	3.1%
15,000	$247.79	$267.02	$19.23	$1,543.39	$1,589.09	$45.70	7.8%	1.2%	3.0%
20,000	$319.79	$343.85	$24.06	$2,049.50	$2,108.80	$59.30	7.5%	1.2%	2.9%

GENERAL SERVICE 50 KW AND OVER

VOLUMES			Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	Load Factor	Kw	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
24,000	56%	60	$543.18	$560.30	$17.12	$2,354.54	$2,404.58	$50.04	3.15%	0.73%	2.13%
40,000	56%	100	$679.27	$683.03	$3.76	$3,698.20	$3,756.82	$58.62	0.55%	0.10%	1.59%
200,000	56%	500	$2,040.19	$1,910.20	($129.99)	$17,134.84	$17,279.14	$144.30	-6.37%	-0.76%	0.84%
400,000	56%	1,000	$3,741.34	$3,444.18	($297.16)	$33,930.64	$34,182.06	$251.42	-7.94%	-0.88%	0.74%
1,000,000	56%	2,500	$8,844.79	$8,046.10	($798.69)	$84,318.04	$84,890.80	$572.76	-9.03%	-0.95%	0.68%
1,250,000	56%	3,100	$10,886.17	$9,886.88	($999.29)	$105,159.76	$105,874.78	$715.02	-9.18%	-0.95%	0.68%
1,600,000	56%	4,000	$13,948.24	$12,648.04	($1,300.20)	$134,705.44	$135,599.56	$894.12	-9.32%	-0.97%	0.66%

STREET LIGHTING

VOLUMES			Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	Kw	Connectio ns	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
193,000	520	3,200	$5,327.70	$13,594.23	$8,266.53	$19,629.67	$28,160.89	$8,531.22	155.2%	42.1%	43.5%
205,000	560	3,400	$5,688.60	$14,512.09	$8,823.49	$20,895.25	$29,999.92	$9,104.67	155.1%	42.2%	43.6%
217,000	**590**	**3,600**	**$6,012.28**	**$15,338.99**	**$9,326.71**	**$22,103.48**	**$31,727.78**	**$9,624.30**	**155.1%**	**42.2%**	**43.5%**
229,000	620	3,800	$6,335.95	$16,165.89	$9,829.94	$23,311.69	$33,455.71	$10,144.02	155.1%	42.2%	43.5%
241,000	660	4,000	$6,696.85	$17,083.75	$10,386.90	$24,577.28	$35,294.68	$10,717.40	155.1%	42.3%	43.6%

BUDGET PROCESS OVERVIEW

OPDC compiles annual budget information for all major components of our financial statements. The completion of the budget process results in budgeted income and cash flow statements as well as balance sheet information for the budget year (in this application the 2010 Test Year) and an updated five year financial plan / forecast. Included in the budget document is a projection of results to current year end (in this application the 2009 Bridge Year).

Operations and Capital Expenditures Budgets:

OPDC's operating and capital expenditures budgets are built from the ground up using a zero based budgeting approach considering the best available information at the time for actual work to be completed. The budget process is in-depth and comprehensive, involving staff with expertise in operations, finance and regulatory affairs.

The capital and operations budgets are compiled using a work order basis for all functional areas involving an in-depth review of operating and capital priorities and requirements. Each work order is "assembled" to include all applicable resources including labour hours and dollars, material costs, third party costs and applicable overheads or indirect costs. The work orders are grouped by general ledger account categories in order to prepare budgeted financial statements.

There are numerous iterations of the capital and operations budgets as all items are reviewed by both the Treasurer and the President prior to final approval by the Board of Directors. All major components of the budget are included in OPDC's long range financial planning model and presented to the Board to ensure that senior management and the Board are aware of budget impacts on cash flows, return on investment, debt-equity ratios and other financial benchmarks. In addition, senior management and the

Board ensure that all aspects of the budget are in line with our strategic objectives over a three to five year basis.

A summary version of OPDC's capital and operations budgets approved by OPDC's Board for the 2010 Test Year is attached as Appendix 1-J.

Revenue Budgets:

OPDC has used a combination of regression and other analysis as well as weather normalization techniques to establish expected billing determinant volumes for 2009 and 2010 distribution revenues as discussed in detail in Exhibit 3 Tab 1. The model then applied the expected throughput volumes for each customer class to existing rates for fiscal 2009 and 2010 in order to determine expected revenues.

Operations, Maintenance and Administration ("OM&A") Expenditure Budgets:

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. Cost increases are identified and reviewed in detail on an account / work order basis, to ensure that optimal value is achieved.

Capital Budgets:

On an annual basis, OPDC prepares a summary of capital projects that it expects to complete over a five year time horizon (see Appendix 1-H). Through this process, the organization's Asset Management Plan provides a critical framework that drives capital expenditure priorities and decisions. Additional influences on any one year's capital budget are many, including; OPDC's capacity to finance capital projects, OPDC corporate objectives as well as outside influences on the organization.

These factors may impact which projects get done in a particular year and projects that may get deferred or even cancelled. OPDC's culture of maintaining a safe and reliable system and ensuring the safety of our staff will always take precedent over all other objectives including financial. Our philosophy is to protect our staff and maintain and enhance (not "harvest") our infrastructure assets.

While OPDC has maintained an admirable record of safety, reliability and customer service to date, we recognize that our resources are being strained. OPDC is concerned about our ability to maintain this level in the future without further investment in resources, both human and financial.

CHANGES IN METHODOLOGY:

Orillia Power Distribution Corporation is not requesting any changes in methodology in the current proceeding.

SCHEDULE OF REVENUE DEFICIENCY

In accordance with regulatory methodology established during previous rates proceedings, Orillia Power Distribution Corporation has calculated its revenue deficiency for the 2010 rates year as attached in Table 1-10. OPDC has calculated its revenue deficiency for the 2010 Test Year at existing 2009 OEB-approved rates to be $671,200 net of taxes. When grossed up for PILs, OPDC's revenue deficiency is $955,200. The revenue requirement work form as required by the filing guidelines has been completed and is included as Appendix 1-P.

CAUSES OF REVENUE DEFICIENCY:

The revenue deficiency is primarily the result of:

- Increases in operations, maintenance and administrative costs including depreciation expense since rates were last rebased. Drivers for the increases were alluded to earlier in this exhibit and are outlined in detail in Exhibit 4.

- Capital Expenditures from 2004 through 2010 have significantly exceeded depreciation levels resulting in increased rate base on which the rate of return is calculated. Changes in the Rate Base are discussed in detail in Exhibit 2.

Further to the increases alluded to above, OPDC discovered that a significant error in OPDC's 2006 EDR filing had been made while examining variances between controllable costs in 2006 Actual and 2006 EDR. This error is explained in detail in Exhibit 4 Tab 3 Schedule 1. **The correction of this omission in distribution costs in the 2006 EDR accounts for almost 40% of the after tax revenue deficiency outlined in Table 1-10 below.**

Table 1-10: 2010 REVENUE DEFICIENCY FOR ORILLIA POWER DISTRIBUTION

Description	2010 Test Revenues at Existing Rates	2010 Test Revenues at Proposed Rates
REVENUES		
Distribution Revenues - existing rates	6,161,700	6,161,700
Other Operating and Interest Revenue	541,300	541,300
Revenue Deficiency		**$955,200**
Total Revenues	**$6,703,000**	**$7,658,200**
DISTRIBUTION COSTS		
Operations & Maintenance, Administrative & General, Billing & Collections	4,346,000	4,346,000
Depreciation & Amortization	1,449,000	1,449,000
Deemed Interest	896,200	896,200
Total Costs and Expenses	**6,691,200**	**6,691,200**
UTILITY EARNINGS AFTER PILS		
Utility Earnings Before PILS	11,800	967,000
Payments in lieu of income taxes (PILS)	18,400	302,400
Utility Net Earnings	**($6,600)**	**$664,600**

REVENUE DEFICIENCY ASSUMING EXISTING RATES MAINTAINED	
Utility Net Earnings - Proposed Rates	664,600
Utility Net Earnings - Assuming Existing Rates Maintained	(6,600)
Revenue Deficiency After Tax - Assuming Existing Rates Maintained	**671,200**
Revenue Deficiency Before Tax - Assuming Existing Rates Maintained	**$955,200**

AUDITED FINANCIAL STATEMENTS AND PRO FORMA INFORMATION

Audited Financial Statements:

Audited financial statements with auditor's opinion for the years ended 2007 and 2008 are attached as Appendices 1-L and 1-M. Orillia Power's Audit Committee reviews the financial statements and notes prior to being issued.

Pro-Forma Financial Statements:

Pro-forma Statements of Earnings and Deficits for 2009 and 2010 are found below in Table 1-11. The statements are in the same format as the audited financial statements. For reference and comparison, 2007 and 2008 audited figures are also included.

Pro-forma Balance Sheets for 2009 and 2010 are found below in Table 1-12. The statements are in the same format as the audited financial statements. For reference and comparison, 2007 and 2008 audited figures are also included.

Six Month Interim Financial Statements:

OPDC Interim financial statements as of June 30, 2009 are attached as Appendix 1-N.

Table 1-11: OPDC Statement of Earnings and Deficit for Years Ended December 31, 2007 to 2010

Description	2007 Actual	2008 Actual	2009 Bridge	2010 Test
REVENUE				
Distribution	$6,201,000	$6,241,000	$6,178,000	$6,208,000
Other	498,000	600,000	460,000	485,000
	6,699,000	6,841,000	6,638,000	6,693,000
COSTS				
Distribution O&M, Billing and Administration	3,857,000	3,878,000	4,185,000	4,311,000
Amortization	1,320,000	1,409,000	1,431,000	1,450,000
	5,177,000	5,287,000	5,616,000	5,761,000
Earnings from operations	1,522,000	1,554,000	1,022,000	932,000
Interest expense (income), taxes				
Interest income	(208,000)	(131,000)	(5,000)	(5,000)
Interest on long term debt	610,000	610,000	610,000	610,000
Income taxes	477,000	473,000	138,000	121,000
	879,000	952,000	743,000	726,000
Net earnings	**$643,000**	**$602,000**	**$279,000**	**$206,000**

Retained earnings (deficit), beginning of year	1,102,000	245,000	(3,153,000)	(3,674,000)
Net earnings	643,000	602,000	279,000	206,000
Dividends	(1,500,000)	(4,000,000)	(800,000)	0
Retained earnings (deficit), end of year	245,000	(3,153,000)	(3,674,000)	(3,468,000)

Table 1-12: OPDC Balance Sheet - December 31, 2007 to 2010

Description	2007 Actual	2008 Actual	2009 Bridge	2010 Test
ASSETS				
Current				
Cash	$3,708,000	$844,000	$318,000	$500,000
Receivables	2,471,000	1,817,000	1,836,000	2,077,000
Unbilled revenue	3,396,000	3,515,000	3,552,000	3,661,000
Payments in lieu of taxes recoverable	166,000	58,000	0	0
Inventory	449,000	484,000	467,000	476,000
Prepaids	60,000	76,000	76,000	76,000
Due from related parties	525,000	500,000	516,000	514,000
	10,775,000	7,294,000	6,765,000	7,304,000
Property and equipment	15,044,000	15,887,000	16,402,000	16,666,000
Regulatory Assets	155,000	0	0	0
	15,199,000	15,887,000	16,402,000	16,666,000
TOTAL ASSETS	**$25,974,000**	**$23,181,000**	**$23,167,000**	**$23,970,000**
LIABILITIES				
Current				
Accounts payable and accrued liabilities	$3,784,000	$4,329,000	$4,439,000	$4,600,000
Customer and retailer deposits	591,000	558,000	558,000	558,000
Employee future benefits	597,000	575,000	553,000	530,000
Regulatory liabilities	408,000	523,000	942,000	1,401,000
Long term debt - City of Orillia	9,762,000	9,762,000	9,762,000	9,762,000
	15,142,000	15,747,000	16,254,000	16,851,000
SHAREHOLDER'S EQUITY				
Contributed capital	2,351,000	2,351,000	2,351,000	2,351,000
Capital Stock	8,236,000	8,236,000	8,236,000	8,236,000
Retained Earnings	245,000	(3,153,000)	(3,674,000)	(3,468,000)
	10,832,000	7,434,000	6,913,000	7,119,000
TOTAL LIABILITIES & EQUITY	**$25,974,000**	**$23,181,000**	**$23,167,000**	**$23,970,000**

AUDITED FINANCIAL RESULTS RECONCILED TO REGULATORY RESULTS

Orillia Power Distribution Corporation advises that regulatory financial results filed vary slightly by immaterial amounts from the 2007 and 2008 Audited Financial Statements.

Reconciliation between financial statements and regulatory financial results are highlighted in Exhibits 2 through 4 within the variance analysis.

ANNUAL REPORT AND MANAGEMENT DISCUSSION & ANALYSIS

Orillia Power Distribution Corporation advises that while it prepares audited financial statements for the parent and subsidiary companies, it does not prepare a formal Annual Report for its parent nor does it prepare a formal year end Management Discussion and Analysis (“MD&A”). OPC does report formally twice a year to its shareholder, the City of Orillia. A copy of the presentation given for OPC’s last annual shareholder meeting is attached as Appendix 1-O.

LEVEL OF MATERIALITY FOR VARIANCE ANALYSIS

Filing Requirements:

Exhibits 2 through 4 include analysis of variances and OPDC justification for changes from year to year in its rate base, capital expenditure levels and operations and maintenance expenditures. The filing requirements for rate applications indicate that the default materiality level for distributors with a revenue requirement of less than $10 million would normally be expected to be $50,000.

Materiality Level Selected:

OPDC has provided explanations for year over year variances greater than $50,000 for all major categories.

APPENDIX 1 – A

A copy of the Orillia Power Distribution Corporation's Distribution licence follows on the next 19 pages.

VT INCEPIT FIDELIS SIC PERMANET
Ontario

Electricity Distribution Licence

ED-2002-0530

Orillia Power Distribution Corporation

Valid Until

March 31, 2023

M. C. Garner

Mark C. Garner
Director of Licensing
Ontario Energy Board

Date of Issuance: June 3, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319 2300, rue Yonge 26e étage
Toronto ON M4P 1E4

2

Electricity Distribution Licence

1 Definitions 3

In this Licence: 4

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee; 5

"**Act**" means the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, as amended; 6

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; 7

"**Board**"means the Ontario Energy Board; 8

"**Director**" means the Director of Licensing appointed under section 5 of the*Act*; 9

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the *Act*, for which a charge or rate has been established in the Rate Order; 10

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems; 11

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A, as amended; 12

"**Licensee**" means Orillia Power Distribution Corporation; 13

"**Market Rules**" means the rules made under section 32 of the *Electricity Act*; 14

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the *Act*; 15

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge; 16

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers; 17

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 18

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the *Electricity Act*; 19

"**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer. 20

2 Interpretation 21

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the *Act* or the *Electricity Act*. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day. 22

3 Authorization Granted under this Licence 23

3.1 The Licensee is authorized, under Part V of the *Act* and subject to the terms and conditions set out in this Licence: 24

a) To own and operate a distribution system in the service area described in Schedule 1 of this Licence; 25

b) To retail electricity for the purposes of fulfilling its obligation under section 29 of the *Electricity Act* in the manner specified in Schedule 2 of this Licence; and , 26

c) To act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the *Electricity Act*. 27

4 Obligation to Comply with Legislation, Regulations and Market Rules 28

4.1 The Licensee shall comply with all applicable provisions of the *Act* and the *Electricity Act* and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation. 29

4.2 The Licensee shall comply with all applicable Market Rules. 30

5 Obligation to Comply with Codes 31

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions to this requirement are set out in Schedule 3 of this Licence: 32

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 33

b) the Distribution System Code; 34

c) the Retail Settlement Code, and; 35

d) the Standard Supply Service Code. 36

5.2 The Licensee shall: 37

a) Make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours and; 38

b) Provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 39

6 Obligation to Provide Non-discriminatory Access 40

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence. 41

7 Obligation to Connect 42

7.1 The Licensee shall connect a building to its distribution system if: 43

a) The building lies along any of the lines of the distributor's distribution system, and 44

b) The owner, occupant or other person in charge of the building requests the connection in writing. 45

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 46

a) The building is within the Licensee's service area as described in Schedule 1, and 47

b) The owner, occupant or other person in charge of the building requests the connection in writing. 48

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board. 49

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or any Codes to which the Licensee is obligated to comply with as a condition of this Licence. 50

8 Obligation to Sell Electricity 51

8.1 The Licensee shall fulfill its obligation under section 29 of the *Electricity Act* to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board. 52

9 Obligation to Maintain System Integrity 53

9.1 The Licensee shall maintain its distribution system to the standards established in the Distribution System Code, Market Rules and have regard to any other recognized industry operating or planning standards adopted by the Board. 54

10 Market Power Mitigation Rebates 55

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 56

11 Distribution Rates 57

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the *Electricity Act* except in accordance with a Rate Order of the Board. 58

12 Separation of Business Activities 59

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board. 60

13 Expansion of Distribution System 61

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make and interconnection except in accordance with the *Act* and Regulations, the Distribution System Code and applicable provisions of the Market Rules. 62

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine. 63

14 Provision of Information to the Board and Director of Licensing 64

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board or the Director, such information as the Board or the Director may require from time to time. 65

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Director of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs. 66

15 Restrictions on Provision of Information 67

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. 68

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed: 69

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 70

b) for billing, settlement or market operations purposes; 71

c) for law enforcement purposes; or 72

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 73

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. 74

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent. 75

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed. 76

16 Customer Complaint and Dispute Resolution 77

16.1 The Licensee shall: 78

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 79

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 80

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours; 81

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 82

e) refer unresolved complaints and subscribe to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Director. The Director will provide reasonable notice to the Licensee of the date this condition becomes effective. 83

17 Term of Licence 84

17.1 This Licence shall take effect on June 3, 2003 and terminate on March 31, 2023. 85

18 Transfer of Licence 86

18.1 In accordance with subsection 18(2) of the *Act*, this Licence is not transferable or assignable without leave of the Board. 87

19 Amendment of Licence 88

19.1 The Board may amend this Licence in accordance with section 74 of the *Act* or section 38 of the *Electricity Act.* 89

20 Fees and Assessments 90

20.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 91

21 Communication 92

21.1 The Licensee shall designate a person that will act as a primary contact with the Director of Licensing on matters related to this Licence. The Licensee shall notify the Director promptly should the contact details change. 93

21.2 All official communication relating to this Licence shall be in writing. 94

21.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 95

a) when delivered in person to the addressee by hand, by registered mail or by courier; 96

b) seven (7) business days after the date of posting if the communication is sent by regular mail; and, 97

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 98

22 Copies of the Licence 99

22.1 The Licensee shall: 100

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours and; 101

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 102

Schedule 1 Definition of Distribution Service Area 103

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8 of this Licence. 104

1 The City of Orillia, County of Simcoe as at October 31, 1991. 105

Schedule 2 Provision of Standard Supply Service 106

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the *Electricity Act*. 107

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders. 108

Schedule 3 List of Code Exemptions 109

This Schedule specifies any specific Code requirements from which the Licensee has been exempt. 110

1 The Licensee is exempt from the requirements of the following sections of the Affiliate Relationships Code for Electricity Distributors and Transmitters under specified conditions as per the Board's Order RP-2002-0071/EB-2002-0365. 111

- Section 2.1.2 A utility shall be physically separated from any affiliate who is an energy service provider. 112

- Section 2.2.2 Where a utility shares information services with an affiliate, all confidential information must be protected from access by the affiliate. Access to a utility's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Services Agreement shall be ensured as necessary, through a review which complies with the provisions of section 5900 of the CICA Handbook. The Board may provide direction regarding the terms of the section 5900 review. The results of any review shall be made available to the Board. 113

- Section 2.2.3 A utility may share employees with an affiliate provided that the employees to be shared are not directly involved in collecting, or have access to, confidential information. 114

- Section 2.2.4 A utility shall not share with an affiliate that is an energy service provider employees that carry out the day-to-day operation of the utility's transmission or distribution network. 115

2 The licensee is exempt from the requirement of sections 2.2.2 of the Standard Supply Service ("SSS") Code under specified conditions as per the Board's Order RP-2002-0071/EB-2002-0365. It states that a distributor that chooses to fulfill its standard supply service obligation directly shall purchase the electricity required to fulfill its obligation to sell electricity to consumers under standard supply service directly from the IMO-administered spot market. 116

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

Appendix A Market Power Mitigation Rebates 118

1 Definitions and Interpretation 119

In this Licence, 120

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 121

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates; 122

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 123

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 124

2 Information Given to IMO 125

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 126

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 127

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* 128

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the 129 rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 130

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 131

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2. 132

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment. 133

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period. 134

3 Pass Through of Rebate 135

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to: 136

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented; 137

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 138

c embedded distributors to whom the distributor distributes electricity. 139

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor. 140

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement: 141

"ONTARIO POWER GENERATION INC. rebate" 142

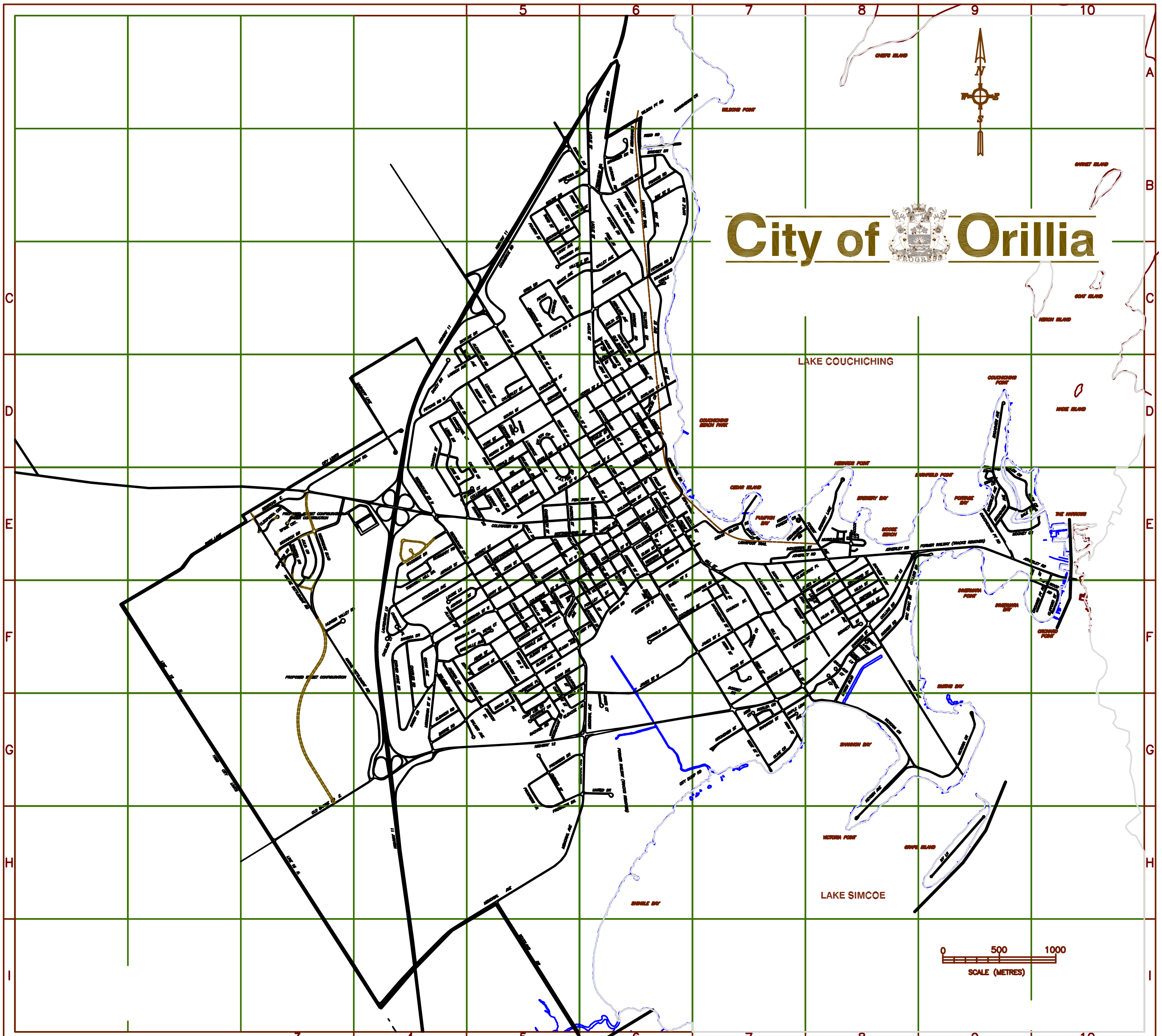
Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 143

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 144

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 145

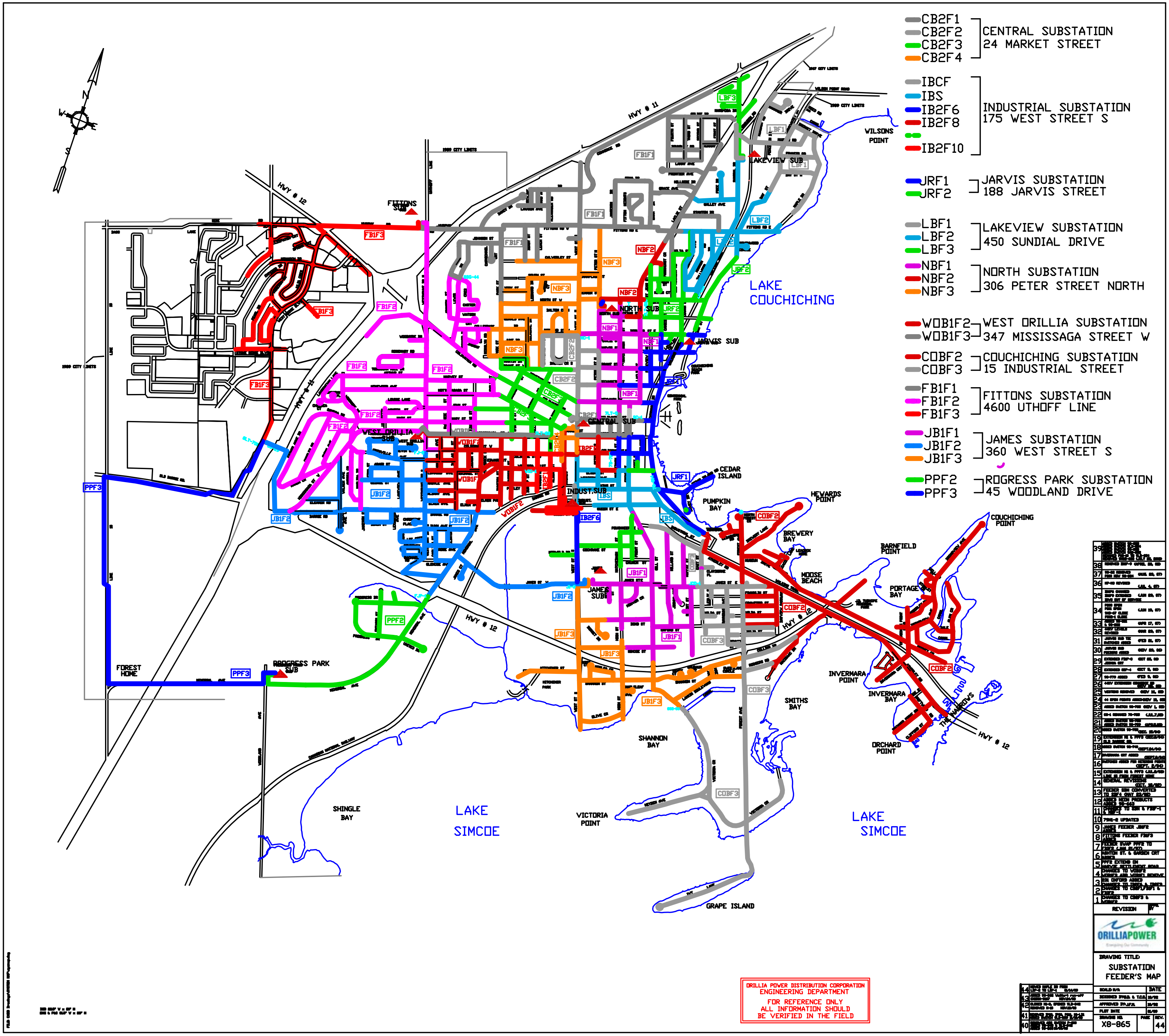
APPENDIX 1 – B

A map of the Orillia Power Distribution Corporation's service territory follows on the next page.


City of Orillia
LAKE COUCHICHING
LAKE SIMCOE
0 500 1000
SCALE (METRES)

APPENDIX 1 – C

A schematic diagram of Orillia Power Distribution Corporation’s system follows on the next page.


CB2F1
CB2F2
CB2F3
CB2F4
CENTRAL SUBSTATION
24 MARKET STREET
IBCF
IBS
IB2F6
IB2F8
IB2F10
INDUSTRIAL SUBSTATION
175 WEST STREET S
JRF1
JRF2
JARVIS SUBSTATION
188 JARVIS STREET
LBF1
LBF2
LBF3
LAKEVIEW SUBSTATION
450 SUNDIAL DRIVE
NBF1
NBF2
NBF3
NORTH SUBSTATION
306 PETER STREET NORTH
WOBIF2
WOBIF3
WEST ORILLIA SUBSTATION
347 MISSISSAGA STREET W
COBF2
COBF3
COUCHICHING SUBSTATION
15 INDUSTRIAL STREET
FB1F1
FB1F2
FB1F3
FITTONS SUBSTATION
4600 UTHOFF LINE
JB1F1
JB1F2
JB1F3
JAMES SUBSTATION
360 WEST STREET S
PPF2
PPF3
RODGRESS PARK SUBSTATION
45 WOODLAND DRIVE
LAKE COUCHICHING
LAKE SIMCOE
LAKE SIMCOE
WILSONS POINT
LAKEVIEW SUB
FITTONS SUB
NORTH SUB
JARVIS SUB
CENTRAL SUB
INDUST.SUB
WEST ORILLIA SUB
JAMES SUB
RODGRESS PARK SUB
FOREST HOME
HWY # 11
HWY # 12
CEDAR ISLAND
PUMPKIN BAY
HEWARDS POINT
BREWERY BAY
BARNFIELD POINT
MOOSE BEACH
PORTAGE BAY
COUCHICHING POINT
INVERMARA POINT
INVERMARA BAY
SMITHS BAY
ORCHARD POINT
THE NARROWS
SHANNON BAY
SHINGLE BAY
VICTORIA POINT
GRAPE ISLAND
ORILLIA POWER DISTRIBUTION CORPORATION
ENGINEERING DEPARTMENT
FOR REFERENCE ONLY
ALL INFORMATION SHOULD
BE VERIFIED IN THE FIELD
ORILLIAPOWER
DRAWING TITLE
SUBSTATION
FEEDER'S MAP
REVISION
DATE
X8-865
44

APPENDIX 1 – D

An organization chart for Orillia Power Distribution Corporation follows on the next page.

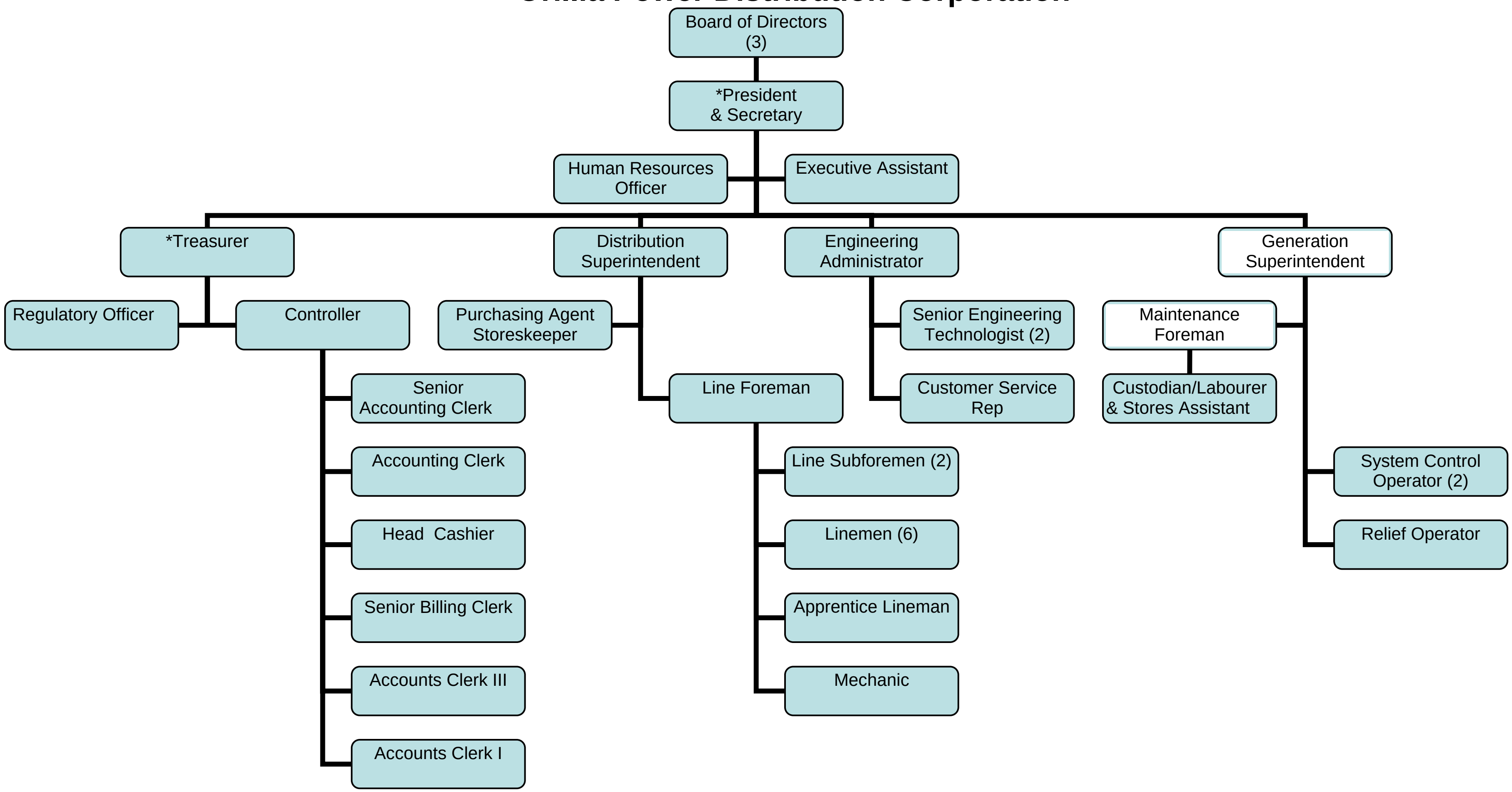
Shared Services and Affiliate Relationships Code Exemptions:

In order to reduce overall distribution costs, OPDC and OPGC share some administrative and technical services among the two corporations. The corporations are guided by a shared services agreement attached in Appendix 1-E. Orillia Power has applied for and received certain exemptions from the Affiliate Relationships Code (ARC) attached in Appendix 1-F.

Services provided by OPDC to OPGC are documented in detail in section 1.01 of the agreement and services provided by OPGC to OPDC are documented in detail in section 1.02 of the agreement.

ORILLIAPOWER
Energizing Our Community

Orillia Power Distribution Corporation



Employees of Orillia Power Distribution Corporation

Employees of Orillia Power Generation Corporation

*Note: Both the President and the Treasurer fill the same positions in Orillia Power Generation Corporation and Orillia Power Corporation.

May 2009

APPENDIX 1 – E

A copy of Orillia Power's services agreement between OPDC and OPGC follows on the next twelve pages.

SERVICES AGREEMENT

BETWEEN

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

AND

ORILLIA POWER GENERATION CORPORATION (OPGC)

As of
JANUARY 1, 2001

TABLE OF CONTENTS

SERVICES AGREEMENT

SERVICES AGREEMENT

THIS AGREEMENT is made as of January 1, 2001

BETWEEN:

ORILLIA POWER DISTRIBUTION CORPORATION, a corporation incorporated under the laws of the Province of Ontario ("OPDC"),

- and -

ORILLIA POWER GENERATION CORPORATION, a corporation incorporated under the laws of the Province of Ontario ("OPGC").

THIS AGREEMENT WITNESSES, that, in consideration of the convenants and agreements herein contained, the parties hereto agree as follows:

ARTICLE 1 – GENERAL

1.01 **Services Provided by OPDC to OPGC**

Subject to the terms and conditions hereof, OPGC (The Corporation) shall retain OPDC (The Service Provider) to carry out services and OPDC shall render the following services to OPGC:

(a) office rent and building maintenance including janitorial services, snow plowing, lawn care, major and minor repairs;

(b) purchasing including procurements at best price, order tracking, delivery of operating and capital items, payment processing and vendor management;

(c) stores management including maintaining stock levels at most efficient levels, issuing and receiving, maintenance of inventory management system and disposition of excess assets;

(d) safety monitoring including the development of policies and procedures, training (awareness and procedures);

(e) environmental compliance monitoring including development of policies and procedures, training (awareness and procedures), regulatory reporting, government liaison and site inspections;

(f) human resources administration including development of policies and procedures, union relations and negotiations, personnel file management and management of employee benefit plans;

(g) bookkeeping including provision of statutory financial and regulatory reporting, management reporting and financial systems administration;

(h) payroll including the maintenance of payroll records and payroll system, calculation of pay and payroll deductions and facilitation of payroll payments;

(i) fleet management including the maintenance of all vehicles in working condition, major and minor repairs, regulatory reporting, expense tracking and fleet management system administration;

(j) financial management including cash administration, investments and debt management, internal audit services and development of financial and accounting policies and procedures;

(k) tax administration including compliance, regulatory reporting, planning, audit reviews and exposure management; and

(l) information technology including provision and management of systems, system and hardware support services, major and minor repairs, development and policies and procedures, and monitoring of information technology developments;

(m) engineering services;

(n) monitoring status of generating facilities using SCADA technology; and

(o) such other services as may from time to time be agreed upon between the parties.

1.02 **<u>Services Provided by OPGC to OPDC</u>**

Subject to the terms and conditions hereof, OPDC (The Corporation) shall retain OPGC (The Service Provider) to carry out services and OPGC shall render the following services to OPDC:

(a) Until the opening of the electricity market is proclaimed (May 1, 2002), the sale of all energy produced (in kWh) by Swift, Minden and Matthias waterpower generation plants and the Diesel plant to the distribution corporation. Once the market is declared open, all energy produced (in kWh) by Matthias and Diesel plants, being physically embedded within the distribution system, to be sold to the distribution corporation on behalf of the City of Orillia customers;

(b) maintenance of substations including major and minor repairs;

(c) staff supervision and technical support of monitoring facilities;

(d) coordination of building maintenance and security; and

(e) such other services as may from time to time be agreed upon between the parties.

1.03 **Term of Agreement**

The provision of services by the Service Provider to the Corporation hereunder shall commence January 1, 2001 and shall continue until terminated by the parties hereto as set forth in Article 5 hereof.

The terms of this agreement may be opened for re-negotiation within 60 days of the anniversary date with the consent of both parties. The new terms would be negotiated to take effect on the anniversary date.

ARTICLE 2 – REMUNERATION OF SERVICE PROVIDER

2.01 **Fee for Services**

The Corporation shall pay the Service Provider for the services provided under this Agreement at a fee at the rate of cost plus a reasonable rate of return on invested capital as determined by the parties, provided that such fee for services at the above-noted rate shall be reviewed by the parties at the option of either party.

2.02 **Reasonable Rate of Return**

Reasonable rate of return on invested capital will normally be defined as the higher of OPDC's rate of return approved by the Ontario Energy Board (OEB) rounded to the nearest 1% (currently 10%) and the prime rate. This rate of return will apply to services provided by either OPDC or OPGC.

2.03 **Expenses**

The Service Provider shall be responsible for all day to day expenses incurred in connection with the services to be provided pursuant to Section 1.01 or 1.02 hereof. However, the Corporation shall reimburse the Service Provider for all extraordinary expenses actually and properly incurred by the Service Provider in the performance of the services hereunder provided that such expenses shall be paid in accordance with the normal practices of the Corporation in force from time to time.

2.04 **Cost Allocation Methodologies**

Different cost allocation methodologies are required depending on the service being provided. Methodologies may be revised from time to time due to changing facts and circumstances. Acceptable methodologies are subject to final approval by the President and Treasurer of Orillia Power Corporation.

Specific methodologies for certain items are outlined below:

(a) for rent and building maintenance outlined in 1.01(a): Costs are allocated based on a reasonable estimate of floor space occupied by the two companies.

(b) for administration services outlined in 1.01(b) to 1.01(l): The labour costs related to staff providing the aforementioned services and other general administrative costs related to running the organization as a whole are allocated to OPDC and OPGC using a percentage determined annually. The allocation is based on a determination of the estimated percentage of time each of the administrative staff would normally spend on activities related to each company.

(c) for engineering services provided by OPDC to OPGC outlined in 1.01(m): All labour time by OPDC staff is charged to OPGC using time sheets. General costs of the engineering department not allocable directly are charged 50% to OPDC and 50% to OPGC.

(d) for SCADA services provided by OPDC to OPGC outlined in 1.01(n): All operations and maintenance costs related to the control centre are to be allocated 50% to OPDC and 50% to OPGC. This percentage is based on a reasonable estimate of time spent by control room staff on activities related to each company.

(e) for energy production supplied to distribution from generation outlined in 1.02(a): Until the market is declared open, each kWh supplied will be priced using the Ontario Energy Board fixed reference price for Standard Supply Service. Once the energy market is open to competition, the price for each kWh supplied will be the Hourly Ontario Energy Price (HOEP) as determined by the spot market.

(f) for substation maintenance outlined in 1.02(b): Labour costs are charged using time sheets. Costs other than labour for maintaining substations are charged directly to OPDC.

2.05 **<u>Invoices</u>**

Payment shall be made to the Service Provider with respect to the fees and expenses referred to in Sections 2.01, 2.02 and 2.03 within 10 days from receipt by the Corporation of proper invoices and vouchers. Invoices will be rendered by the Service Provider to the Corporation either monthly, quarterly or annually. The invoice timing for a particular service (ie. monthly, quarterly or annually) will depend on the materiality of the charge or to ensure administrative ease. What is material will be determined by the Treasurer who is responsible for the financial well being of both entities. As a minimum, all services related to a particular fiscal year will be invoiced as part of that year-end. The Service Provider shall also provide a report annually of all expenses incurred in connection with the provision of services pursuant to Section 1.01 and 1.02 hereof.

ARTICLE 3 – COVENANTS OF SERVICE PROVIDER

3.01 **Services**

The Service Provider shall render performance of the services hereunder to the best of the Service Provider's ability and in a competent and professional manner.

3.02 **Time of Services**

The Service Provider shall devote such of its time and attention to the business of the Corporation as may be agreed to by the Service Provider and the Corporation. The time of service to be provided hereunder by the Service Provider shall be as agreed to from time to time by the Corporation and the Service Provider. Subject to the obligations of the Service Provider hereunder, the Service Provider shall be free to offer services to any other person.

3.03 **Licenses and Permits**

The Service Provider shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulation in connection with the provision of the services hereunder and the Service Provider shall when requested provide the Corporation with adequate evidence of his compliance with this Section 3.03.

3.04 **Rules and Regulations**

The Service Provider shall comply, while on the premises used by the Corporation, with all the rules and regulations of the Corporation from time to time in force which are brought to its notice of which it could be reasonably aware.

3.05 **Insurance**

The Service Provider shall pay for and maintain for the benefit of the Service Provider and the Corporation, with insurers or through the appropriate government department and in an amount and in a form acceptable to the Corporation, appropriate insurance concerning the operations and liabilities of the Service Provider relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by the Service Provider to any employees of the Service Provider and public liability and property damage insurance.

3.06 **Indemnity**

The Service Provider shall indemnify and save the Corporation harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Corporation or its officers, employees or agents may suffer as a result of the negligence of the Service Provider and in the performance or non-performance of this Agreement.

3.07 **Non-disclosure**

The Service Provider shall not (either during the term of this Agreement or at any time thereafter) disclose any information relating to the private or confidential affairs of the Corporation or relating to any secrets of the Corporation to any person other than with the consent of the Corporation.

ARTICLE 4 – TERMINATION

4.01 **Termination by Corporation or Service Provider for Cause**

The Corporation or the Service Provider may terminate this Agreement at any time in the event of the failure of the other party to comply with any of the provisions hereunder upon such other party being notified in writing by the party alleging such failure and failing to remedy such failure within 30 days of receiving such notice.

4.02 **Termination by Corporation or Service Provider on Notice**

The Corporation or Service Provider may terminate this Agreement upon the giving of 60 days written notice to the other party. Notwithstanding the foregoing, the Corporation may terminate this Agreement immediately upon paying to the Service Provider 60 days fee for services in lieu of such notice.

4.03 **Provisions which Operate Following Termination**

Notwithstanding any termination of this Agreement for any reason whatsoever and with or without cause, the provisions of Sections 3.06 and 3.07 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination.

ARTICLE 5 – ARBITRATION

5.01 **Arbitration of Disputes**

Any disputes arising between the parties relating to the interpretation of any provision of this Agreement or other matters which under the provision of this Agreement are referred to arbitration shall be settled by arbitration in accordance with the provisions of Section 5.02.

5.02 **Appointment of Arbitrator and Arbitration Procedures**

(a) In the event of disagreement, litigation or dispute with respect to the interpretation, application or execute of one or the other of the provisions of this Agreement the parties hereto renounce their right to institute legal proceedings and undertake to submit such disagreement, litigation or dispute to the final decision pursuant to Arbitration in accordance with Schedule "A" hereto.

(b) The fees and disbursements of the arbitrator shall be shared equally by the parties to this Agreement.

(c) The arbitration provided for in this Agreement is subject to the provisions of the Arbitration Act (Ontario), to the extent that such provisions are not incompatible herewith.

ARTICLE 6 – INTERPRETATION AND ENFORCEMENT

6.01 **Sections and Headings**

The divisions of this Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms of "this Agreement", "hereof", "hereunder", and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

6.02 **Extended Meanings**

In this Agreement words importing the singular number only include the plural and *vice versa*, words importing any gender include all genders and words importing persons include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and *vice versa.*

6.03 **Benefit of Agreement**

This Agreement shall enure to the benefit of and be binding upon successors and assigns of the Service Provider and the Corporation, respectively.

6.04 **Entire Agreement**

This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof and cancels and supersedes any prior understandings and agreements between the parties hereto with respect thereto. There are no representations, warranties, forms, conditions, undertakings or collateral agreements, express implied or statutory between the parties other than as expressly set forth in this Agreement.

6.05 **Amendments and Waivers**

No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the parties hereto. No waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

6.06 **Assignment**

Except as may be expressly provided in this Agreement, neither party hereto may assign his or its rights or obligations under this Agreement without the prior written consent of the other party hereto.

6.07 **Severability**

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of any such provision and all other provisions hereof shall continue in full force and effect.

6.08 **Notices**

Any demand, notice or other communication to be made or given in connection with this Agreement shall be made or given in writing and may be made or given by personal delivery or by registered mail addressed to the recipient as follows:

Orillia Power Distribution Corporation
360 West St. S., P.O. Box 398
Orillia ON L3V 6J9
Attn: Pat Hurley

Orillia Power Generation Corporation
360 West St. S., P.O. Box 398
Orillia ON L3V 6J9
Attn: John Mattinson

or any other such address or individual as may be designated by notice by either party to the other. Any demand, notice or other communication made or given by personal delivery shall be conclusively deemed to have been given on the day of actual delivery thereof and, if made or given by registered mail, on the 5th day, other than a Saturday, Sunday or statutory holiday in Ontario, following the deposit thereof in the mail. If the party giving any demand, notice or other communication knows or ought reasonably to know of any difficulties with the postal system which might affect the delivery of the mail, any such demand, notice or other communication shall not be mailed but shall be made or given by personal delivery.

6.09 **Further Assurances**

Each party must from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

6.10 **Governing Law**

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

6.11 **Attornment**

For the purpose of all legal proceedings this Agreement shall be deemed to have been performed in the Province of Ontario and, subject to Article 5 of this Agreement, the courts of the Province of Ontario shall have jurisdiction to entertain any action arising under this Agreement. Subject to Article 5 of this Agreement, the Corporation and the Service Provider each hereby attorns to the jurisdiction of the courts of the Province of Ontario provided that nothing herein contained shall prevent the Corporation from proceeding at its election against the Service Provider in the courts of any other province or country.

IN WITNESS WHEREOF the parties have executed this Agreement.

ORILLIA POWER DISTRIBUTION CORPORATION

Per: ______________________
Patrick J. Hurley, B. Math, CMA

ORILLIA POWER GENERATION CORPORATION

Per: ______________________
John F. Mattinson, P. Eng.

SCHEDULE "A"

ARBITRATION

Any dispute between the parties hereto, or any matter to be submitted to arbitration hereunder, whether arising during the period of this Agreement or at any time thereafter which touches upon the validity, construction, meaning, performance or effect of this Agreement or the rights and liabilities of the parties hereto or any matter arising out of or connected with this Agreement shall be subject to arbitration pursuant to the Arbitrations Act (Ontario) and as provided in this Schedule A and the decision shall be final and binding as between the parties hereto and shall not be subject to appeal.

Any arbitration to be carried out under this Schedule A shall be subject to the following provisions, namely:

The party desiring arbitration shall nominate one (1) arbitrator and shall notify the other party hereto of such nomination. Such notice shall set forth a brief description of the matter submitted for arbitration and, if appropriate, the paragraph hereto pursuant to which such matter is so submitted. Such other party shall within thirty (30) days after receiving such notice nominate an arbitrator and the two (2) arbitrators shall select a chairman of the arbitral tribunal to act jointly with them. If the said arbitrators shall be unable to agree in the selection of such chairman, the chairman shall be designated by a Judge of the Ontario Court (General Division) or any successor hereto upon an application. The arbitration shall take place in the City of Orillia and the chairman shall fix the time and place in the City of Orillia for the purpose of hearing such evidence and representations as either of the parties may present and subject to provisions hereto, the decision of the arbitrators and chairman or of any two (2) of them in writing shall be binding upon the parties both in respect of procedure and the conduct of the parties during the proceedings and the final determination of the issues herein. Said arbitrators and chairman shall, after hearing evidence and representations that the parties may submit, make their decision and reduce the same to writing and deliver one (1) copy thereof to each of the parties hereto. The majority of the chairman and arbitrators may determine any matters of procedure for the arbitration not specified herein.

If the party hereto receiving the notice of the nomination of an arbitrator by the party desiring arbitration fails within the thirty (30) days to nominate an arbitrator, then the arbitrator nominated by the party desiring arbitration may proceed alone to determine the dispute in such manner and at such time as he shall think fit and his decision shall, subject to the provisions hereof, be binding upon the parties.

Notwithstanding the foregoing, any arbitration may be carried out by a single arbitrator if the parties agree here so agree, in which event the provisions of this paragraph shall apply, mutatis mutandis.

APPENDIX 1 – F

The Energy Board's Decision and Order regarding exemptions from the Affiliate Relationships Code applied for and received by OPDC follows on the next ten pages.

Ontario Energy Board
P.O. Box 2319
26th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
26e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY PRIORITY POST

October 22, 2002

RECEIVED
OCT 24 2002
ORILLIA POWER CORPORATION

Mr. John Mattinson
General Manager & Secretary
Orillia Power Distribution Corporation
Box 398
360 West St. S.
Orillia, ON
L3V 6J9

Dear Mr. Mattinson:

Re: Application for Exemption from the Affiliate Relationship Code for Electricity Distributors and Transmitters
<u>Board File No. RP-2002-0071/EB-2002-0365</u>

The Board has today issued its Decision and Order in the above matter and an executed copy is enclosed herewith.

Yours truly,

Peter H. O'Dell
Assistant Board Secretary

cc: P. Hurley

Encl.

RP-2002-0071
EB-2002-0365

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B;

AND IN THE MATTER OF an application by Orillia Power Distribution Corporation for exemptions from sections 2.1.2, 2.2.2, 2.2.3, 2.2.4, 2.3.1, 2.3.2 of the Affiliate Relationships Code for Electricity Distributors and Transmitters and exemption from section 2.2.2 of the Standard Supply Service Code for Electricity Distributors;

BEFORE: Paul Sommerville
Presiding Member

Bob Betts
Member

DECISION AND ORDER

October 22, 2002

1 THE APPLICATION AND BACKGROUND

1.1 On May 31, 2002 Orillia Power Distribution Corporation("Orillia Power Distribution" or the "Applicant") filed an application (the "Application") with the Ontario Energy Board (the "Board") for exemptions from sections 2.1.2, 2.2.2, 2.2.4, 2.3.1 and 2.3.2 of the Affiliate Relationships Code for Electricity Distributors and Transmitters (the "ARC"). By correspondence of August 13, 2002, Orillia Power Distribution amended its original application by applying for an additional exemption from section 2.2.3 of the ARC. On October 15, 2002, the Applicant filed an application with the Board for an exemption from section 2.2.2 of the Standard Supply Service Code for Electricity Distributors (the "SSS" Code).

1.2 Orillia Power Distribution and Orillia Power Generation Corporation (the "Companies") intend to enter into a Services Agreement in accordance with section 2.2.1 of the ARC to provide services to each other.

1.3 Orillia Power Distribution proposes to provide the following services to Orillia Power Generation Corporation ("Orillia Power Generation"): office rent and building maintenance, purchasing, stores management, safety monitoring, environmental compliance monitoring, human resources administration, bookkeeping, payroll, fleet management, financial management, tax administration, information technology, engineering services, and monitoring status of generating facilities using SCADA (Supervisory Control And Data Acquisition) technology.

1.4 Orillia Power Distribution proposes that Orillia Power Generation provide the following services to Orillia Power Distribution: generating and supplying electricity, maintenance of substations, staff supervision and technical support of monitoring facilities, and coordination of building maintenance and security.

2. SPECIFIC EXEMPTION APPLICATIONS

Physical Separation

2.1 Section 2.1.2 of the ARC provides:
A utility shall be physically separated from any affiliate who is an energy service provider.

2.2 In its letter dated May 29, 2002, Orillia Power Distribution states that Orillia Power Corporation, the holding company of Orillia Power Distribution and Orillia Power Generation, presently has a single control centre with an operator and a SCADA system to monitor and control the distribution system and generation assets of the Companies. A requirement for physical separation of the Companies would greatly increase cost and inefficiency from historical levels, thus, negatively affecting the Companies. As the Companies are not in the electricity retail business, there is no competitive advantage gained by the absence of physical separation.

Access to Confidential Information

2.3 Sections 2.2.2, 2.2.3 and 2.2.4 of the ARC provide:

> 2.2.2 Where a utility shares information services with an affiliate, all confidential information must be protected from access by the affiliate. Access to a utility's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Services Agreement shall be ensured as necessary, through a review which complies with the provisions of section 5900 of the CICA Handbook. The Board may provide direction regarding the terms of the section 5900 review. The results of any review shall be made available to the Board.
>
> 2.2.3 A utility may share employees with an affiliate provided that the employees to be shared are not directly involved in collecting, or have access to, confidential information.
>
> 2.2.4 A utility shall not share with an affiliate that is an energy service provider employees that carry out the day-to-day operation of the utility' s transmission or distribution network.

2.4 Orillia Power Distribution requested exemptions from sections 2.2.2, 2.2.3, 2.2.4 of the ARC to allow the Companies to share confidential information and to share employees that are involved in the operation of Orillia Power

Distribution's distribution network for the purpose of providing services to each other in accordance with their Services Agreement.

2.5 Orillia Power Distribution submitted that precluding the use of generation personnel to work on distribution substations will negatively affect costs and flexibility of the Companies. The shared confidential information and employees are used to efficiently operate the generation facilities and meet Orillia Power Distribution's obligations required by its distribution licence. The non-disclosure of confidential information to other persons is addressed in the Services Agreement.

Cost of Services

2.6 Section 2.3.1, 2.3.2 and 2.3.3 of the ARC provide:

> 2.3.1 Where a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the fair market value of the service, resource or product.
>
> 2.3.2 In purchasing a service, resource or product, from an affiliate, a utility shall pay no more than the fair market value. For the purpose of purchasing a service, resource or product a valid tendering process shall be evidence of fair market value.
>
> 2.3.3 Where a fair market value is not available for any product, resource or service, a utility shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of the utility' s approved rate of return or the bank prime rate.

2.7 Orillia Power Distribution has requested exemptions from sections 2.3.1 and 2.3.2 of the ARC to allow the Companies to provide service to each other at cost-based price without cross subsidization. Pursuant to the Services Agreement, the cost-based price reflects the costs of producing the service, including a reasonable rate of return on invested capital which is defined as the higher of Orillia Power Distribution's rate of return approved by the Board or the bank prime rate.

2.8 On August 13, 2002, by way of a modified Services Agreement, Orillia Power Distribution submitted that the actual costs for each type of service shall be tracked within the Companies' workorder system. Specific costs will be allocated to each company based on supporting documents. Electricity generated and supplied to Orillia Power Distribution by Orillia Power Generation will be the Hourly Ontario Energy Price ("HOEP") as determined by the spot market .

2.9 On June 19, 2002 and July 2, 2002, Orillia Power Distribution further clarified that the generation capacity of Orillia Power Generation is not pivotal in IMO Administered Market during peak demand and Orillia Power Generation will not demand a price above competitive levels. Orillia Power Generation has no other bilateral agreements except for agreements regarding transactions for Standard Supply Service ("SSS") with Orillia Power Distribution and Hydro One Networks in which it is embedded. As a market price taker, Orillia Power Generation does not demand a price higher than HOEP.

3. BOARD FINDINGS

3.1 The Board has proceeded with the Application without a hearing as no one other than the applicant is materially adversely affected by the application. While the Board has considered all of the evidence filed in this proceeding, the Board has only referenced the evidence to the extent necessary to provide background to its findings.

3.2 The Board finds approving the exemptions from sections 2.1.2, 2.2.2, 2.2.3 and 2.2.4 is in the public interest as it will allow the continued realization of economic efficiency of the Companies and continued savings to ratepayers.

3.3 The Board is satisfied that Orillia Power Generation, a market price taker, does not demand a price above competitive levels and so Orillia Power Distribution is in compliance with section 2.3.2 of the ARC for the purchase of power from Orillia Power Generation. The Services Agreement is to be signed by the Companies to prevent Orillia Power Distribution from cross-subsidizing Orillia Power Generation or providing it with favored treatment.

3.4 The Board notes that the Applicant's proposal regarding cost of services including a reasonable rate of return meets the requirement of section 2.3.3 of the Code. Therefore, granting the exemptions from sections 2.3.1 and 2.3.2 is not necessary at this time.

3.5 The Board finds that granting the exemption from section 2.2.2 of the SSS Code and allowing Orillia Power Distribution to purchase the electricity from

Orillia Power Generation to fulfill its obligation to sell electricity to consumers under standard supply service is in public interest.

4. THE BOARD HEREBY ORDERS THAT:

Orillia Power Distribution Corporation is exempted from sections 2.1.2, 2.2.2, 2.2.3, 2.2.4 of the ARC and section 2.2.2 of the SSS Code. The exemptions are provided under the following conditions:

1. The exemptions only apply with respect to Orillia Power Distribution Corporation's relationship with Orillia Power Generation Corporation and not with respect to any other affiliate of Orillia Power Distribution Corporation.
2. The shared facilities, employees and confidential information shall only be used for the purpose of services provided by the Companies to each other pursuant to the Services Agreement.

3. The activities of the Companies are bound by the Services Agreement which is subject to the Board's review and investigation. No amendment shall be made to the Services Agreement without the prior approval of the Board. The Applicant shall report to the Board before any services are provided under clause 1.01(o) or clause 1.02(e) of the Services Agreement.

4. The Applicant shall report to the Board any material changes with respect to the materials filed in support of the Application and the above conditions within fifteen days of the date upon which such change occurs. At that time, the Board may review these exemptions to ensure that any potential harm to ratepayers and competitors of Orillia Power Generation caused by any

unfair competitive advantages or preferential treatment which Orillia Power Generation may obtain from Orillia Power Distribution as a result of the exemptions is minimized. The Board may upon reviewing the report of the Applicant, revoke some or all of the exemptions granted by this order or vary the conditions set out in this order.

DATED at Toronto October 22, 2002.

Paul Sommerville
Presiding Member

Bob Betts
Member

APPENDIX 1 – G

OPDC's Key Financial Results Summary from 2007 to 2013 if Status Quo maintained (rates not rebased) follows in the next five pages.

ORILLIA POWER DISTRIBUTION CORPORATION

Key Financial Results

For Years Ending:

2007 - 2013

STATUS QUO
NO RATE REBASING APPLICATION SUBMITTED

Last Modified:	
3-Aug-09	*10:45 AM*

ORILLIAPOWER
Energizing Our Community

2010 RATE APPLICATION
PROJECTION FOR 2009 TO 2013
STATUS QUO - NO RATE APPLICATION

EARNINGS & RETURN ON EQUITY	Dec-07	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13
DISTRIBUTION INCOME STATEMENT							
Operating revenues							
Distribution revenues	$6,201,000	$6,241,000	$6,178,000	$6,208,000	$6,236,000	$6,289,000	$6,327,000
Other revenues	$498,000	$600,000	$460,000	$485,000	$477,000	$480,000	$479,000
	$6,699,000	$6,841,000	$6,638,000	$6,693,000	$6,713,000	$6,769,000	$6,806,000
Operating expenses							
Distribution O&M, Billing and Administration	$3,857,000	$3,878,000	$4,185,000	$4,311,000	$4,462,000	$4,620,000	$4,782,000
Amortization	$1,320,000	$1,409,000	$1,431,000	$1,450,000	$1,495,000	$1,497,000	$1,523,000
	$5,177,000	$5,287,000	$5,616,000	$5,761,000	$5,957,000	$6,117,000	$6,305,000
Earnings from operations	$1,522,000	$1,554,000	$1,022,000	$932,000	$756,000	$652,000	$501,000
Interest expense (income), taxes and donations							
Interest income	($208,000)	($131,000)	($5,000)	($6,000)	($9,000)	($14,000)	($23,000)
Interest on long term debt	$610,000	$610,000	$610,000	$610,000	$610,000	$610,000	$610,000
Income taxes	$477,000	$473,000	$138,000	$121,000	$48,000	$17,000	($27,000)
	$879,000	$952,000	$743,000	$725,000	$649,000	$613,000	$560,000
Net earnings	**$643,000**	**$602,000**	**$279,000**	**$207,000**	**$107,000**	**$39,000**	**($59,000)**
EQUITY - DISTRIBUTION	$10,832,000	$7,434,000	$6,913,000	$7,120,000	$7,020,000	$6,952,000	$6,854,000
After tax Return on Average Equity - LDC	**5.7%**	**6.6%**	**3.9%**	**3.0%**	**1.5%**	**0.6%**	**-0.9%**

2010 RATE APPLICATION
PROJECTION FOR 2009 TO 2013
STATUS QUO - NO RATE APPLICATION

DISTRIBUTION REVENUES	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**
CUSTOMER BASE AND GROWTH RATE							
Residential	11,102	11,261	11,382	11,504	11,628	11,752	11,879
General service	1,678	1,671	1,683	1,695	1,708	1,720	1,733
Total	**12,780**	**12,932**	**13,065**	**13,199**	**13,335**	**13,473**	**13,612**
Residential	0.9%	1.4%	1.1%	1.1%	1.1%	1.1%	1.1%
General Service	-0.1%	-0.4%	0.7%	0.7%	0.7%	0.7%	0.7%
Percentage change	**0.8%**	**1.2%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**
CUSTOMER KWH CONSUMPTION GROWTH (DECLINE) RATE							
Distribution kWh sold	321,106,000	319,008,000	312,509,000	311,571,000	315,088,000	315,341,000	316,767,000
Percentage Change in customer consumption	0.2%	-0.7%	-2.0%	-0.3%	1.1%	0.1%	0.5%
REVENUES							
Distribution revenues	**$6,201,000**	**$6,241,000**	**$6,178,000**	**$6,208,000**	**$6,236,000**	**$6,289,000**	**$6,327,000**
Sale of power revenues	$23,391,000	$22,791,000	$23,160,000	$24,026,000	$25,102,000	$25,115,000	$25,237,000
	$29,592,000	$29,032,000	$29,338,000	$30,234,000	$31,338,000	$31,404,000	$31,564,000
Percentage Change in LDC revenues	-3%	1%	-1%	0%	0%	1%	1%
REVENUES PER KWH							
Distribution revenues per kWh	**$0.019**	**$0.020**	**$0.020**	**$0.020**	**$0.020**	**$0.020**	**$0.020**
Sale of power revenues per kWh	$0.073	$0.071	$0.074	$0.077	$0.080	$0.080	$0.080
Total revenues per kWh	**$0.092**	**$0.091**	**$0.094**	**$0.097**	**$0.099**	**$0.100**	**$0.100**

CAPITAL & OM&A EXPENDITURES	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**
CAPITAL EXPENDITURES							
Capital expenditures - Distribution	$1,157,000	$2,252,000	$1,946,000	$1,714,000	$2,561,000	$1,983,000	$1,778,000
% Change	-21.8%	94.6%	-13.6%	-11.9%	49.4%	-22.6%	-10.3%
OPERATIONS & MAINTENANCE, BILLING & ADMINISTRATION							
Operations & maintenance	$1,807,000	$1,855,000	$1,870,000	$1,999,000	$2,070,000	$2,144,000	$2,219,000
Billing	$910,000	$894,000	$1,064,000	$1,019,000	$1,055,000	$1,092,000	$1,130,000
Administration	$1,140,000	$1,129,000	$1,251,000	$1,293,000	$1,337,000	$1,384,000	$1,433,000
Total	$3,857,000	$3,878,000	$4,185,000	$4,311,000	$4,462,000	$4,620,000	$4,782,000
% Change	6.7%	0.5%	7.9%	3.0%	3.5%	3.5%	3.5%
OM&A PER CUSTOMER							
Operations & maintenance per customer	$142	$144	$144	$152	$156	$160	$164
Billing per customer	$71	$70	$82	$78	$80	$81	$83
Administration per customer	$90	$88	$96	$98	$101	$103	$106
Total OM&A per customer	**$303**	**$302**	**$322**	**$328**	**$336**	**$345**	**$353**
COMBINED EXPENDITURES (CAPITAL & OPERATIONS)							
Combined expenditures - Distribution	**$5,014,000**	**$6,130,000**	**$6,131,000**	**$6,025,000**	**$7,023,000**	**$6,603,000**	**$6,560,000**
% Change	-1.6%	22.3%	0.0%	-1.7%	16.6%	-6.0%	-0.7%
COMBINED EXPENDITURES PER CUSTOMER							
Combined capital and OM&A per customer	**$394**	**$477**	**$472**	**$459**	**$529**	**$493**	**$484**

2010 RATE APPLICATION
PROJECTION FOR 2009 TO 2013
STATUS QUO - NO RATE APPLICATION

OTHER KEY STATISTICS AND RATIOS	Dec-07	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13
CUSTOMERS / DISTRIBUTION EMPLOYEE							
Total number of employees - Consolidated	42.0	43.0	43.0	44.0	44.0	44.0	44.0
Number of employees - Distribution	28.0	28.0	28.0	29.0	29.0	29.0	29.0
Customers per Distribution employee	**456**	**462**	**467**	**455**	**460**	**465**	**469**
RATIO OF DEBT TO DEBT PLUS EQUITY							
Debt / (Debt + Equity) - Distribution	47.4%	56.8%	58.5%	57.8%	58.2%	58.4%	58.8%
INTEREST COVERAGE RATIO							
Interest Coverage Ratio - Distribution	2.8	2.8	1.7	1.5	1.3	1.1	0.9
CASH BALANCE AT YEAR END	$3,708,000	$844,000	$472,000	$655,000	$591,000	$986,000	$1,598,000

APPENDIX 1 – H

OPDC's Capital Expenditure Plans to 2015 follows in the next four pages.

Orillia Power Distribution Corporation
Capital Plans From 2010 to 2015

	2010	2011	2012	2013	2014	2015	Future Projects
Land and Buildings							
Easements	8,000	10,000	10,000	10,000	10,000	10,000	
Building upgrades	12,000	30,000	30,000	30,000	30,000	30,000	
	20,000	40,000	40,000	40,000	40,000	40,000	-
Subtransmission							
Subtransmission Pole Replacement	88,000	100,000	100,000	100,000	100,000	100,000	
Load Break Switches	119,000						
	207,000	100,000	100,000	100,000	100,000	100,000	-
Substations							
Install oil retainers at Substations	40,000						
Feeder Cable Replacement - Progress Park Sub	27,000						
Feeder Cable Replacement - Couchiching Sub	27,000						
Feeder Cable Replacement - Progress Park Sub							
Meter upgrades & Reconfiguration (M4, M7, M8)	15,000						
Replace Industrial Substation		800,000					
13.8 substation - Couchiching Pt. Rd.			750,000				
Harvie Settlement Rd. Substation							1,000,000
	109,000	800,000	750,000	-	-	-	1,000,000

Orillia Power Distribution Corporation
Capital Plans From 2010 to 2015

	2010	2011	2012	2013	2014	2015	Future Projects
Overhead							
Distribution Pole Replacement	211,000	225,000	225,000	235,000	235,000	250,000	
Patrick St Rebuild - Nottawasaga to Brant St.	198,000						
Conductor upgrades & reconductoring	17,000						
Reconstruct rear of BDO Dunwoody	78,000						
Colbourne to Andrew Re-build	189,000						
Line 15 North - Pick up Load Transfer Cust's	119,000						
O/H Services Misc.	39,000	40,000	40,000	40,000	40,000	40,000	
Re-Build West St. - James St. to by-pass				300,000			
Re-Build King St. - Cedar Island Rd. to Front (Rexton)							250,000
Re-Build James St. - High St. to East St.						400,000	
Replace 44 kV ABS with Load Interrupters (4)		120,000	125,000	130,000	50,000	50,000	
Re-Build Matchedash St. N. - Coldwater Rd to North St.			350,000				
Rebuild West St. N. - North St. to Fittons Rd. (20 poles)					450,000		
Motorize 4 Load Interruptors		120,000	100,000	60,000	30,000		
Rebuild & Restring Colborne St. - West St. to the Esplande - Ph 1		110,000					
Rebuild & Restring Colborne St. - West St. to the Esplande - Ph 2		110,000					
Phase 1 Dalton Cres/Lawrence Ave - replace rearlot buss						150,000	
Tallwood / Harmon - Replace Rearlot Buss						150,000	
Rebuild Fittons Rd. E. - West St. to Bay St					450,000		
Phase 2 Dalton Cres/Lawrence Ave. - replace rearlot buss						280,000	
Sundial Drive - Fittons to Laclie				450,000			
Rebuild Brant St. W.		100,000					
Relocate 44kV North of Central Sub to West St. N.		300,000					
Rebuild Coldwater Rd. - West St. to Emily						350,000	
Replace Rearlot Secondary - Delia, Hilda & Franklin Streets							330,000
Rebuild Barrie Road - Westmount to Mississaga St. W.							450,000
	851,000	1,125,000	840,000	1,215,000	1,255,000	1,670,000	1,030,000

Orillia Power Distribution Corporation
Capital Plans From 2010 to 2015

	2010	2011	2012	2013	2014	2015	Future Projects
Underground							
Primary replacement	46,000	20,000	20,000	20,000			
Re-Cable Raymond St subdivision							
Underground Services Misc.	57,000	60,000	60,000	60,000	60,000	60,000	
Victoria Cres - Lankin Blvd south to riser	123,000						
Recable Central Sub - CB2F1 & CB2F2		130,000					
Joint Use Ducts on Old Muskoka Rd							100,000
Recable Brewery Lane							120,000
Duct Maple Leaf Crescent	26,000						
Duct King's Crt.	39,000						
Duct Lahay Ave.	11,000						
Recable Central Sub (CB2F3)			60,000				
Recable Andrea Cres & Marlisa Dr.				150,000			
Phase 1 Dalton Cres/Lawrence Ave. area ducting							250,000
Recable North Sub (NBF1 & NBF2)				80,000			
Phase 2 Ducting Dalton Cres / Lawrence Ave area							400,000
Tallwood / Harmon - Install Front Lot Primary							150,000
Cable Phase 1 Dalton Cres/Lawrence Ave. (front lot primary)							250,000
Cable Phase 2 Dalton Cres/Lawrence Ave. (front lot primary)							300,000
Install Single Phase Ducts - Delia, Hilda, Franlin Streets							180,000
Install Underground Primary - Delia, Hilda, Franlin Streets							130,000
	302,000	210,000	140,000	310,000	60,000	60,000	1,880,000

	2010	2011	2012	2013	2014	2015	Future Projects
DistributionTransformers & Meters							
Transformer Installation & Replacements	45,000	45,000	50,000	50,000	50,000	50,000	
New Meters	5,000	10,000	10,000	10,000	15,000	15,000	
	50,000	55,000	60,000	60,000	65,000	65,000	-

Orillia Power Distribution Corporation
Capital Plans From 2010 to 2015

	2010	2011	2012	2013	2014	2015	Future Projects
Office Equipment and Furniture							
Replace Photocopier / Printer / Scanner unit							
Miscellaneous Office Equipment	10,000	3,000	3,000	3,000	3,000	3,000	
	10,000	3,000	3,000	3,000	3,000	3,000	-
Computer Hardware and Software							
Desktop / Laptop Upgrades, Peripherals, other hardware	15,000	20,000	20,000	20,000	20,000	20,000	
Conversion to Harris Northstar V.6 & SQL Database		80,000					
Engineering Plotter	10,000						
Upgrade to GP V.10	32,000						
Other software							
	57,000	100,000	20,000	20,000	20,000	20,000	-
Vehicles							
Replace Service Truck							
Replace T18	41,000						
Replace T 4	41,000						
Replace T 21					450,000		
	82,000	-	-	-	450,000	-	-
Tools and Equipment							
Major Tools & Equipment over $1000	26,000	28,000	30,000	30,000	32,000	32,000	
SCADA							
SCADA System Upgrade		100,000					
Totals	**1,714,000**	**2,561,000**	**1,983,000**	**1,778,000**	**2,025,000**	**1,990,000**	**3,910,000**

APPENDIX 1 – I

OPDC's Key Financial Results Summary from 2007 to 2013 if rates put forth in rate application are approved (rates rebased) follows in the next five pages.

ORILLIA POWER DISTRIBUTION CORPORATION

Key Financial Results

For Years Ending:

2007 - 2013

INCLUDES IMPACT OF CHANGES FROM 2010 RATE APPLICATION (REBASING)

Last Modified:	
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ORILLIA POWER
DISTRIBUTION

2010 RATE APPLICATION
PROJECTION FOR 2009 TO 2013
2010 RATE REBASING IMPACT

EARNINGS & RETURN ON EQUITY	Dec-07	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13
DISTRIBUTION INCOME STATEMENT							
Operating revenues							
Distribution revenues	$6,201,000	$6,241,000	$6,178,000	$6,725,000	$7,197,000	$7,258,000	$7,302,000
Other revenues	$498,000	$600,000	$460,000	$485,000	$477,000	$480,000	$479,000
	$6,699,000	$6,841,000	$6,638,000	$7,210,000	$7,674,000	$7,738,000	$7,781,000
Operating expenses							
Distribution O&M, Billing and Administration	$3,857,000	$3,878,000	$4,205,000	$4,346,000	$4,499,000	$4,658,000	$4,821,000
Amortization	$1,320,000	$1,409,000	$1,431,000	$1,450,000	$1,495,000	$1,497,000	$1,523,000
	$5,177,000	$5,287,000	$5,636,000	$5,796,000	$5,994,000	$6,155,000	$6,344,000
Earnings from operations	$1,522,000	$1,554,000	$1,002,000	$1,414,000	$1,680,000	$1,583,000	$1,437,000
Interest expense (income), taxes and donations							
Interest income	($208,000)	($131,000)	($5,000)	($7,000)	($13,000)	($20,000)	($29,000)
Interest on long term debt	$610,000	$610,000	$610,000	$699,000	$744,000	$744,000	$744,000
Income taxes	$477,000	$473,000	$132,000	$243,000	$294,000	$266,000	$224,000
	$879,000	$952,000	$737,000	$935,000	$1,025,000	$990,000	$939,000
Net earnings	**$643,000**	**$602,000**	**$265,000**	**$479,000**	**$655,000**	**$593,000**	**$498,000**
EQUITY - DISTRIBUTION	$10,832,000	$7,434,000	$6,899,000	$7,378,000	$7,554,000	$7,492,000	$7,397,000
After tax Return on Average Equity - LDC	**5.7%**	**6.6%**	**3.7%**	**6.7%**	**8.8%**	**7.9%**	**6.7%**

DISTRIBUTION REVENUES	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**
CUSTOMER BASE AND GROWTH RATE							
Residential	11,102	11,261	11,382	11,504	11,628	11,752	11,879
General service	1,678	1,671	1,683	1,695	1,708	1,720	1,733
Total	**12,780**	**12,932**	**13,065**	**13,199**	**13,335**	**13,473**	**13,612**
Residential	0.9%	1.4%	1.1%	1.1%	1.1%	1.1%	1.1%
General Service	-0.1%	-0.4%	0.7%	0.7%	0.7%	0.7%	0.7%
Percentage change	**0.8%**	**1.2%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**
CUSTOMER KWH CONSUMPTION GROWTH (DECLINE) RATE							
Distribution kWh sold	321,106,000	319,008,000	312,509,000	311,571,000	315,088,000	315,341,000	316,767,000
Percentage Change in customer consumption	0.2%	-0.7%	-2.0%	-0.3%	1.1%	0.1%	0.5%
REVENUES							
Distribution revenues	**$6,201,000**	**$6,241,000**	**$6,178,000**	**$6,725,000**	**$7,197,000**	**$7,258,000**	**$7,302,000**
Sale of power revenues	$23,391,000	$22,791,000	$23,160,000	$24,026,000	$25,102,000	$25,115,000	$25,237,000
	$29,592,000	$29,032,000	$29,338,000	$30,751,000	$32,299,000	$32,373,000	$32,539,000
Percentage Change in LDC revenues	-3%	1%	-1%	9%	7%	1%	1%
REVENUES PER KWH							
Distribution revenues per kWh	**$0.019**	**$0.020**	**$0.020**	**$0.022**	**$0.023**	**$0.023**	**$0.023**
Sale of power revenues per kWh	$0.073	$0.071	$0.074	$0.077	$0.080	$0.080	$0.080
Total revenues per kWh	**$0.092**	**$0.091**	**$0.094**	**$0.099**	**$0.103**	**$0.103**	**$0.103**

CAPITAL & OM&A EXPENDITURES	Dec-07	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13
CAPITAL EXPENDITURES							
Capital expenditures - Distribution	$1,157,000	$2,252,000	$1,946,000	$1,714,000	$2,561,000	$1,983,000	$1,778,000
% Change	-21.8%	94.6%	-13.6%	-11.9%	49.4%	-22.6%	-10.3%
OPERATIONS & MAINTENANCE, BILLING & ADMINISTRATION							
Operations & maintenance	$1,807,000	$1,855,000	$1,870,000	$1,999,000	$2,070,000	$2,144,000	$2,219,000
Billing	$910,000	$894,000	$1,064,000	$1,019,000	$1,055,000	$1,092,000	$1,130,000
Administration	$1,140,000	$1,129,000	$1,271,000	$1,328,000	$1,374,000	$1,422,000	$1,472,000
Total	$3,857,000	$3,878,000	$4,205,000	$4,346,000	$4,499,000	$4,658,000	$4,821,000
% Change	6.7%	0.5%	8.4%	3.4%	3.5%	3.5%	3.5%
OM&A PER CUSTOMER							
Operations & maintenance per customer	$142	$144	$144	$152	$156	$160	$164
Billing per customer	$71	$70	$82	$78	$80	$81	$83
Administration per customer	$90	$88	$98	$101	$104	$106	$109
Total OM&A per customer	**$303**	**$302**	**$324**	**$331**	**$339**	**$348**	**$356**
COMBINED EXPENDITURES (CAPITAL & OPERATIONS)							
Combined expenditures - Distribution	**$5,014,000**	**$6,130,000**	**$6,151,000**	**$6,060,000**	**$7,060,000**	**$6,641,000**	**$6,599,000**
% Change	-1.6%	22.3%	0.3%	-1.5%	16.5%	-5.9%	-0.6%
COMBINED EXPENDITURES PER CUSTOMER							
Combined capital and OM&A per customer	**$394**	**$477**	**$473**	**$461**	**$532**	**$495**	**$487**

OTHER KEY STATISTICS AND RATIOS	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**
CUSTOMERS / DISTRIBUTION EMPLOYEE							
Total number of employees - Consolidated	42.0	43.0	43.0	44.0	44.0	44.0	44.0
Number of employees - Distribution	28.0	28.0	28.0	29.0	29.0	29.0	29.0
Customers per Distribution employee	**456**	**462**	**467**	**455**	**460**	**465**	**469**
RATIO OF DEBT TO DEBT PLUS EQUITY							
Debt / (Debt + Equity) - Distribution	47.4%	56.8%	58.6%	57.0%	56.4%	56.6%	56.9%
INTEREST COVERAGE RATIO							
Interest Coverage Ratio - Distribution	2.8	2.8	1.7	2.0	2.3	2.2	2.0
CASH BALANCE AT YEAR END	$3,708,000	$844,000	$461,000	$821,000	$952,000	$1,351,000	$1,965,000

APPENDIX 1 – J

OPDC's Capital and Operations Budget Summaries including a summary of actual expenditures back to 2004 through to the 2010 Test Year follows in the next eight pages.

ORILLIA POWER CORPORATION

2010 BUDGET

DISTRIBUTION

PRESENTED TO THE BOARD - JULY 23, 2009

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ORILLIA POWER DISTRIBUTION CORPORATION

2010 BUDGET – EXECUTIVE SUMMARY

The 2010 Distribution budget (capital and operating) is being presented early in order to have a board approved budget that can be incorporated into the 2010 rate application being prepared for submission to the Ontario Energy Board. The Generation budget will be prepared in the fall and presented to the board. At that time, a full consolidated budget will also be prepared for review.

The 2010 operating budget, including billing and administration, is $4,346,000. This represents a 3% increase over our 2009 year end projection and a 12% over our 2008 actual results. In addition to general inflationary pressure on wages and other costs, increased regulatory expenses and a proposed new hire in engineering are the main factors driving the increase.

The 2010 capital budget is focused on making strategic investments that will continue to strengthen our infrastructure, maintain our high level of system reliability for our customers and improve long-term financial performance of the organization. With the completion of several major sub-transmission projects over the past few years, in 2009, our primary focus shifted from sub-transmission towards projects related to distribution lines. Several of these projects scheduled for 2009 will be deferred to 2010 as a result of major initiatives such as the new library and Lakehead University that are demanding a significant amount of our resources. Distribution projects remain the primary focus of the 2010 capital budget.

Our total capital spending for Distribution is budgeted at $1,714,000 for 2010. This represents a 12% decrease from our 2009 year end projection, but is trending just marginally above our average annual capital spending over the past six years.

To summarize, the budgeted operations and capital spending will result in infrastructure improvements, while maintaining focus on operational efficiency, cost management and safety of employees and the public.

ORILLIA POWER CORPORATION

2010 DISTRIBUTION BUDGET SUMMARY
OPERATIONS AND CAPITAL

DISTRIBUTION CORPORATION BUDGET SUMMARY	ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	BUDGET 31-Dec-09	PROJECTION 31-Dec-09	BUDGET 31-Dec-10	Pg 1
CAPITAL EXPENDITURES SUMMARY									
Distribution Expenditures	1,822,000	1,413,000	1,553,000	1,165,000	2,252,000	1,868,000	1,946,000	**1,714,000**	2
2010 Budget as a percentage of above	94%	121%	110%	147%	76%	92%	88%	**100%**	
2009 Projection as a percentage of 2009 Budget							**104%**		
Average 2004 - 2009							1,690,000		
OPERATIONS EXPENDITURES SUMMARY									
Distribution Expenditures	1,500,000	1,588,000	1,690,000	1,808,000	1,855,000	1,870,000	1,870,000	**1,999,000**	3
2010 Budget as a percentage of above	133%	126%	118%	111%	108%	107%	107%	**100%**	
2009 Projection as a percentage of 2009 Budget							**100%**		
Average 2004 - 2009							1,720,000		
ADMINISTRATION / BILLING / SERVICE CENTRE EXPENDITURES SUMMARY									
Distribution Expenditures	1,775,000	2,189,000	1,926,000	2,049,000	2,023,000	2,193,000	2,335,000	**2,347,000**	3
2010 Budget as a percentage of above	132%	107%	122%	115%	116%	107%	101%	**100%**	
2009 Projection as a percentage of 2009 Budget							**106%**		
Average 2004 - 2009							2,050,000		
COMBINED EXPENDITURES SUMMARY									
Distribution Expenditures	5,097,000	5,190,000	5,169,000	5,022,000	6,130,000	5,931,000	6,151,000	**6,060,000**	
2010 Budget as a percentage of above	119%	117%	117%	121%	99%	102%	99%	**100%**	
2009 Projection as a percentage of 2009 Budget							**104%**		
Average 2004 - 2009							5,460,000		

ORILLIA POWER CORPORATION

2010 DISTRIBUTION BUDGET SUMMARY
OPERATIONS AND CAPITAL

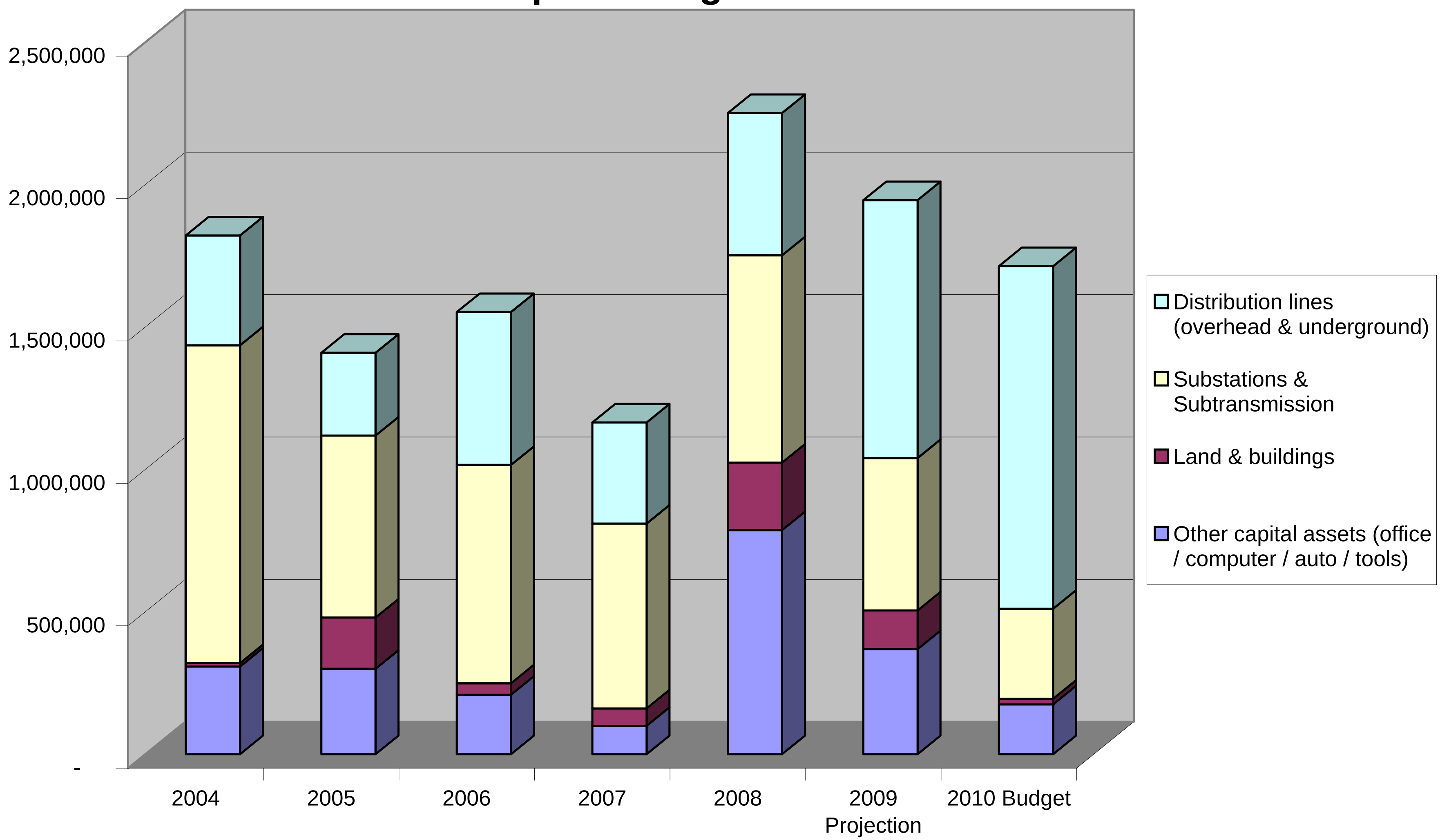
DISTRIBUTION CORPORATION CAPITAL EXPENDITURES SUMMARY	ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	BUDGET 31-Dec-09	PROJECTION 31-Dec-09	BUDGET 31-Dec-10	Pg 2
CAPITAL EXPENDITURES SUMMARY FOR DISTRIBUTION CORPORATION									
Land & buildings	12,000	180,000	40,000	61,000	237,000	8,000	136,000	**20,000**	4
Subtransmission lines 44kv	1,116,000	641,000	767,000	649,000	728,000	365,000	535,000	**316,000**	4
Distribution lines (overhead & underground)	386,000	291,000	537,000	355,000	500,000	1,155,000	906,000	**1,203,000**	4
Other capital assets (office / computer / auto / tools)	308,000	301,000	209,000	100,000	787,000	340,000	369,000	**175,000**	5
	1,822,000	**1,413,000**	**1,553,000**	**1,165,000**	**2,252,000**	**1,868,000**	**1,946,000**	**1,714,000**	
2010 Budget as a percentage of above	94%	121%	110%	147%	76%	92%	88%	**100%**	
2009 Projection as a percentage of 2009 Budget							**104%**		
Average 2004 - 2009							1,690,000		
2010 Distribution Capital Budget - Major Items Summary									
Install oil retainers at Substations								**40,000**	9
Substation feeder upgrades and rerouting								**54,000**	9
Pole replacement 44 kV lines								**88,000**	10
Load Break Switches								**119,000**	10
Pole replacement - 13.8 kV lines								**211,000**	11
Patrick St Rebuild - Nottawasaga to Brant St.								**198,000**	11
Reconstruct rear of BDO Dunwoody								**78,000**	11
Colbourne to Andrew Re-build								**189,000**	11
Line 15 North - Pick up Load Transfer Cust's								**119,000**	11
Services								**60,000**	12
Victoria/Lankin to Riser Cable Upgrade								**123,000**	13
Underground ducting and primary replacement								**158,000**	13
Transformer Installation & Replacements								**45,000**	14
Software upgrade - Great Plains Accounting (IFRS version)								**32,000**	17
Rolling Stock - Replacements for Trucks 4 & 18								**82,000**	18
Other Miscellaneous Projects								**118,000**	
								1,714,000	

ORILLIA POWER CORPORATION

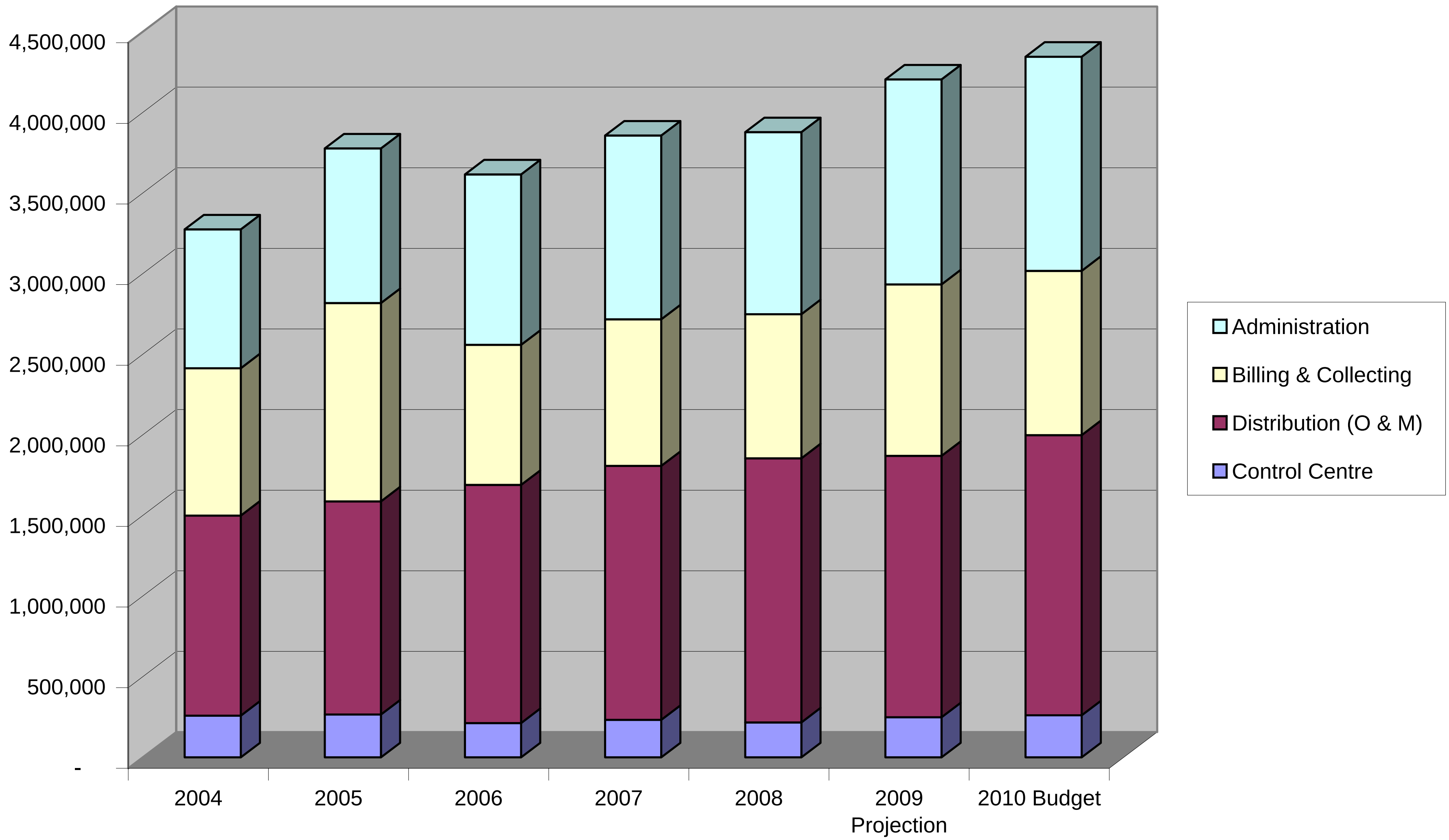
2010 DISTRIBUTION BUDGET SUMMARY
OPERATIONS AND CAPITAL

DISTRIBUTION CORPORATION OPERATIONS EXPENDITURES SUMMARY	ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	BUDGET 31-Dec-09	PROJECTION 31-Dec-09	BUDGET 31-Dec-10	Pg 3
OPERATIONS EXPENDITURES SUMMARY FOR DISTRIBUTION CORPORATION									
Distribution									
Subtransmission lines	73,000	67,000	127,000	108,000	81,000	83,000	83,000	**102,000**	**22**
Substations	138,000	100,000	189,000	125,000	202,000	173,000	173,000	**160,000**	**22**
Overhead line maintenance	381,000	348,000	331,000	543,000	467,000	419,000	419,000	**447,000**	**22**
Underground line maintenance	86,000	145,000	113,000	77,000	113,000	109,000	109,000	**98,000**	**22**
Transformer & meter maintenance	66,000	91,000	94,000	92,000	112,000	142,000	142,000	**108,000**	**22**
Supervision & engineering	326,000	363,000	379,000	438,000	499,000	518,000	518,000	**645,000**	**22**
Utilization	56,000	75,000	107,000	52,000	23,000	34,000	34,000	**31,000**	**23**
Control Centre	259,000	266,000	213,000	233,000	217,000	249,000	249,000	**261,000**	**23**
Service centre	115,000	133,000	137,000	140,000	141,000	143,000	143,000	**147,000**	**24**
	1,500,000	1,588,000	1,690,000	1,808,000	1,855,000	1,870,000	1,870,000	**1,999,000**	
Administration									
Billing & collecting	914,000	1,230,000	869,000	909,000	894,000	914,000	1,064,000	**1,019,000**	**24**
Administration	784,000	870,000	966,000	1,047,000	1,035,000	1,184,000	1,176,000	**1,230,000**	**24**
Service Centre	77,000	89,000	91,000	93,000	94,000	95,000	95,000	**98,000**	**24**
	1,775,000	2,189,000	1,926,000	2,049,000	2,023,000	2,193,000	2,335,000	**2,347,000**	
	3,275,000	**3,777,000**	**3,616,000**	**3,857,000**	**3,878,000**	**4,063,000**	**4,205,000**	**4,346,000**	
2010 Budget as a percentage of above	133%	115%	120%	113%	112%	107%	103%	**100%**	
2009 Projection as a percentage of 2009 Budget							**103%**		
Average 2004 - 2009							3,770,000		

ORILLIA POWER CORPORATION
Distribution - Capital Budget Breakdown 2004 - 2010



ORILLIA POWER CORPORATION
Distribution - Operations Budget Breakdown 2004 - 2010



Orillia Power Distribution Corporation

2008 Actual Operations Expenditures		**3,878,000**
Significant factors impacting year over year expenditures:		
Inflationary pressure (Wages & other costs)	116,000	
Provision for Pliant	150,000	
Regulatory costs (including rate application)	47,000	
IFRS consulting & support	10,000	**327,000**
Sub transmission maintenance (air breaks & tree trimming)	52,000	
Matthias line maintenance (transfer to Generation Co.)	(32,000)	
Miscellaneous	(16,000)	
2009 Projected Operations Expenditures		**4,205,000**
Significant factors impacting year over year expenditures:		
Inflationary pressure (Wages & other costs)	126,000	
New Eng Tech Q1-10 (Response to increased regulatory reporting, etc.)	100,000	
Reduction in bad debt expenses	(95,000)	
Increased premiums for credit insurance	20,000	**141,000**
Reduction in capital taxes	(13,000)	
IFRS consulting & support	20,000	
Miscellaneous	(17,000)	
2010 Budgeted Operations Expenditures		**4,346,000**

APPENDIX 1 – K

An article in ZeroQuest Magazine illustrating OPDC's focus on safety follows on the next page.

E&USA [redacted]8.30

September 2009 | Vol 12 | Issue 9

www.eusa.on.ca

ZeroQuest®
MAGAZINE

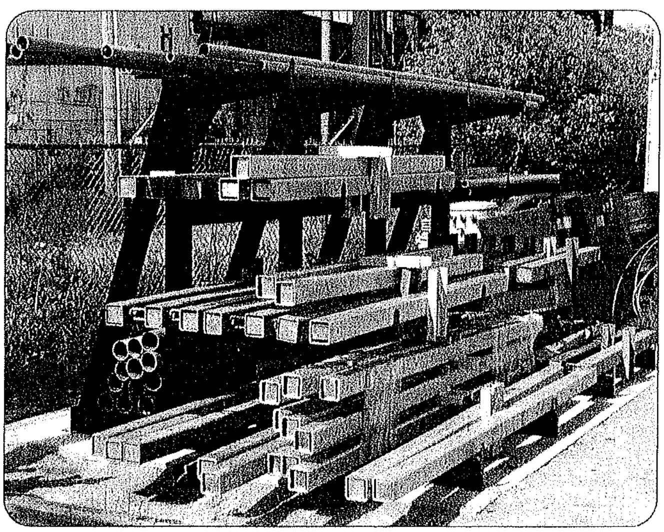
ORILLIA POWER CREATES NEW RACK DESIGN

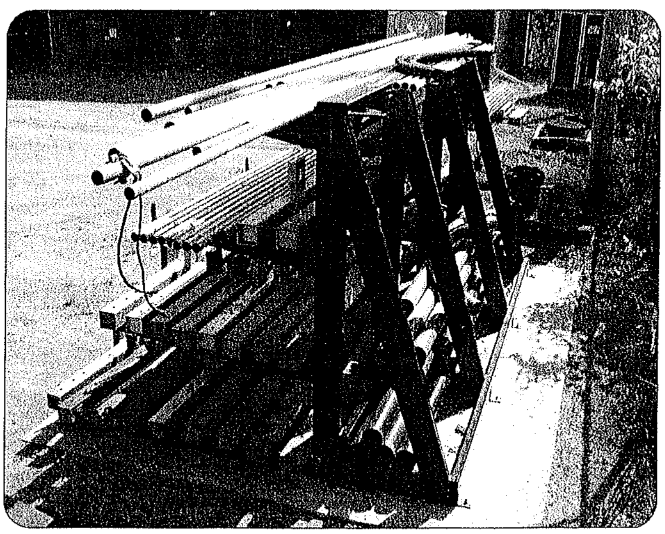
Storage of supplies is an important aspect of good housekeeping which, as we know, is an important part of eliminating many safety risks in any warehouse facility or storage yard.

Orillia Power has replaced their storage rack area for cross arms with a new rack system designed in house by Peter Kosik. He had the structure tested and approved to ensure it was safe to carry the weight of the cross arms.

In the past the utility kept its 5',7, and 9' steel cross-arms on an aluminum structure that provided no fork-truck access (for retrieval and placement) and lifting items on and off posed a potential source of injury. Peter Kosik came up with the notion of a racking concept that would allow for the safe and easy retrieval and placement of this awkward and heavy material. My plan consisted of designing a cross-arm storage system that could accommodate each size of cross arm in the quantities the utility would be storing. It had to be fork-truck accessible and wide enough to handle assorted lengths of galvanized steel tubing used on load interrupters as well as PVC ducting material. In addition the company wanted it low enough so as not to have the material positioned very high up in order to avoid further risk. After calculating the minimum load capacities each level required for safe storage, a design was determined and submitted to a local engineering services firm for an engineering review and certification. Once it was verified to be in conformance to CAN/CSA-S16-01 Limit States Design Of Steel Structures the project was well on its way.

Fabrication and installation was performed – complete with a concrete pad for extra stability and Hilti fastening for extra rigidity. The unit was also stamped with an official name plate verifying the load capacity limitations and official designation as "CAR1".





APPENDIX 1 – L

OPDC's Audited Financial Statements with audit opinion attached for the year ended December 31, 2007 follows on the next eighteen pages.

Orillia Power Distribution Corporation
Financial Statements
December 31, 2007

ORILLIAPOWER

Energizing Our Community

Contents

Grant Thornton

Auditors' report

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To the Directors of

Orillia Power Corporation

We have audited the balance sheet of Orillia Power Distribution Corporation as at December 31, 2007 and the statements of earnings 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 cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Ontario

March 18, 2008

Chartered accountants,

Licensed public accountants

Orillia Power Distribution Corporation
Statements of Earnings and Retained Earnings

(In Thousands)

Year Ended December 31		2007		2006
Revenue				
Sale of power	$	**23,391**	$	22,615
Distribution		**6,201**		6,387
Other		**498**		2,261
		30,090		31,263
Costs				
Power purchased		**23,391**		22,615
Operations, maintenance and administration		**3,857**		3,616
Amortization		**1,320**		1,359
		28,568		27,590
Earnings from operations		**1,522**		3,673
Interest income		**208**		198
Interest on long term debt		**(610)**		(610)
Earnings before payments in lieu of taxes		**1,120**		3,261
Payments in lieu of taxes (Note 11)		**477**		700
Net earnings	**$**	**643**	$	2,561
Retained earnings (deficit), beginning of year	**$**	**1,102**	$	(1,459)
Net earnings		**643**		2,561
Dividends		**(1,500)**		-
Retained earnings, end of year	**$**	**245**	$	1,102

See accompanying notes to the financial statements.

Orillia Power Distribution Corporation
Balance Sheet

(In Thousands)

December 31		2007		2006
Assets				
Current				
Cash	$	**3,708**	$	5,134
Receivables		**2,471**		2,246
Unbilled revenue		**3,396**		3,420
Payments in lieu of taxes recoverable		**166**		-
Inventory		**449**		448
Prepaids		**60**		31
Due from related parties (Note 3)		**525**		526
		10,775		11,805
Property and equipment (Note 4)		**15,044**		15,207
Regulatory assets (Note 5)		**155**		462
	$	**25,974**	$	27,474
Liabilities				
Current				
Payables and accruals	$	**3,784**	$	4,101
Payments in lieu of taxes payable		**-**		87
		3,784		4,188
Customer and retailer deposits		**591**		740
Employee future benefits (Note 6)		**597**		608
Regulatory liabilities (Note 5)		**408**		487
Long term debt (Note 7)		**9,762**		9,762
		15,142		15,785
Shareholder's Equity				
Capital stock (Note 8)		**8,236**		8,236
Contributed capital		**2,351**		2,351
Retained earnings		**245**		1,102
		10,832		11,689
	$	**25,974**	$	27,474

Commitments and contingent liability (Note 9 and 10)

On Behalf of the Board

_______________ Director _______________ Director

See accompanying notes to the financial statements.

Orillia Power Distribution Corporation
Statement of Cash Flows

(In Thousands)

Year Ended December 31	2007	2006
Increase (decrease) in cash and cash equivalents		
Operating		
Net earnings	**$ 643**	$ 2,561
Amortization	**1,320**	1,359
Employee future benefits	**(11)**	(22)
	1,952	3,898
Change in non-cash operating working capital (Note 12)	**(949)**	(313)
	1,003	3,585
Financing		
Dividends	**(1,500)**	-
Investing		
Net reduction in regulatory assets	**307**	669
Net reduction in regulatory liabilities	**(79)**	(2,521)
Net additions to property and equipment	**(1,157)**	(1,479)
	(929)	(3,331)
Net (decrease) increase in cash and cash equivalents	**(1,426)**	254
Cash and cash equivalents, beginning of year	**5,134**	4,880
Cash and cash equivalents, end of year	**$ 3,708**	$ 5,134

See accompanying notes to the financial statements.

1. Nature of operations

The Company distributes electricity to the residents and businesses in the City of Orillia, under a license granted by the Ontario Energy Board (OEB). The Company is regulated by the OEB under the authority of the Ontario Energy Board Act, 1998. The OEB prescribes license requirements and conditions to electricity distributors, which may include among other things, specified accounting records, regulatory accounting principles, separation of accounts for distinct businesses and guidelines for establishing just and reasonable rates.

2. Summary of significant accounting policies

Cash and cash equivalents

Cash and cash equivalents include cash on hand and balances with banks.

Inventory

Inventory consists of repair parts, supplies and materials for maintenance and future capital expansion. The inventory is valued at the lower of the weighted average cost of similar items and net realizable value.

Rate regulation

The rates of the Company's electricity distribution business are subject to regulation by the Ontario Energy Board (OEB), under the authority granted by the Ontario Energy Board Act (1998). The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity, ensuring continued rate protection for rural and remote electricity consumers, and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. This change in timing gives rise to the recognition of regulatory assets and liabilities. These regulatory assets and liabilities reflect the fact that revenue and expenses are recognized in the financial statements in different periods consistent with their inclusion in rates, as directed by the regulator, than would be the case for an enterprise that is unregulated. Specific regulatory assets and liabilities recognized at December 31, 2007 are disclosed in Note 5.

The Company reviews all regulatory assets for likelihood of recovery and believes that it is probable that they will be factored into the setting of future rates. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

2. Summary of significant accounting policies (Continued)

Revenue recognition

Energy revenue attributable to the delivery of electricity is recorded on the basis of regular meter readings using rates approved by the Ontario Energy Board and recognized in the period that power is consumed. Customer usage since the date of the last meter reading to year end is estimated as unbilled revenue.

Property and equipment

Property and equipment are recorded at cost and include contracted services, materials, labour, engineering costs and overheads. Significant renewals and enhancements to existing assets are capitalized only if the service life of the asset is extended, reliability or productivity is improved above original design standards or associated operating costs are lowered. Maintenance and repair costs are expensed as incurred.

Property and equipment is amortized using the straight-line method over periods approximating its estimated useful life as follows:

Land rights	5	years
Buildings	10-30	years
Sub-stations/sub-transmission lines	25-35	years
Distribution system	25-35	years
Other capital assets	5-10	years

When property and equipment is sold or scrapped, the cost of the asset and the related accumulated amortization is removed when identifiable from the accounts, with the resulting net gain or loss being included in operations for the year.

Fixed assets retirement obligations

Canadian generally accepted accounting principles (GAAP) require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated fixed assets.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its fixed assets for an indefinite period, no removal date can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations can not be made at this time.

2. Summary of significant accounting policies (Continued)

Corporate income and capital taxes

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

The Company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the Company at that time. This regulation accounting treatment differs from Canadian generally accepted accounting principles for enterprises operating in a non-regulated environment.

Employee future benefits

Pension plan
The Company provides pension benefits for its employees through the Ontario Municipal Employees Retirement System (OMERS). This multi-employer pension plan provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. It is a contributory defined benefit pension plan financed by equal contributions from participating employers and employees and by investment earnings of the fund. The Company recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension plan
The Company provides life insurance benefits to employees hired prior to January 1, 2008 when they are no longer providing active service. The Company is also obligated to provide certain medical and dental benefits to age 65 under an early retirement plan for a limited number of former employees. Employee future benefits expense is recognized in the period in which the employee renders services. Employee future benefits other than pension plans are recorded on an accrual basis. The accrued benefit obligation and current service costs are calculated using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the present value of expected future benefits attributed to employee's services rendered in the period.

(In Thousands)

2. Summary of significant accounting policies (Continued)

Use of estimates

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

3. Related party transactions

2007 2006

Transactions involving the sale of electricity are in the normal course of operations and are measured at the exchange amount, which is equal to the fair value as prescribed by regulation. Transactions involving other services have been recorded in these financial statements at the carrying amounts, which were equal to historical cost or fair value. Fair values represent fees for equivalent services provided to third parties in the normal course of operations as prescribed by regulations. The Company had the following related party transactions:

		2007		2006
Orillia Power Generation Corporation - related company				
Services purchased	$	**248**	$	325
Power purchased on behalf of Orillia customers		**758**		921
Services provided		**819**		861
City of Orillia - the shareholder of Orillia Power Corporation, the parent company				
Power sold		**1,277**		1,291
Other services sold		**79**		105
Purchases		**97**		75
Property taxes		**64**		64
Interest paid		**610**		610
Orillia Power Corporation - parent company				
Administrative services provided		**9**		9
SCBN Telecommunications Inc. - affiliated company				
Services purchased		**8**		32
Services provided		**-**		17

Balances outstanding at December 31:

Due from Orillia Power Generation Corporation - related company	$	**525**	$	523
Due from Orillia Power Corporation - parent company		**-**		3
	$	**525**	$	526

(In Thousands)

3. Related party transactions (Continued)

During the year, the Company paid interest of $610 (2006 - $610) on a promissory note payable, to the City of Orillia, the shareholder of Orillia Power Corporation, the parent Company. Included in payables and accruals is $174 (2006 - $167) due to the City of Orillia. Included in receivables is $47 (2006 - $66) due from the City of Orillia.

4. Property and equipment

			2007	2006
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 206	$ -	**$ 206**	$ 189
Land rights	31	24	**7**	4
Buildings	1,232	669	**563**	570
Terminal stations	378	378	**-**	-
Sub-stations/sub-transmission lines	10,464	4,523	**5,941**	5,492
Distribution system	19,008	11,264	**7,744**	8,253
Other capital assets	5,608	5,025	**583**	699
	$ 36,927	$ 21,883	**$ 15,044**	$ 15,207

5. Regulatory assets and liabilities

As described in Note 2, the Company has recorded the following regulatory assets and liabilities:

	2007	2006
Regulatory assets		
Market opening costs	**$ (3)**	$ 236
Other regulatory assets	**158**	226
	$ 155	$ 462
Regulatory liabilities		
Retail settlement variances	**406**	441
Other regulatory liabilities	**2**	46
	$ 408	$ 487

(In Thousands)

5. Regulatory assets and liabilities (Continued)

Market opening costs
In a letter dated December 19, 2003, the Minister of Energy granted approval for distributors to make application to the OEB with regard to recovery through rates of distribution regulatory assets related to market opening whose previous inclusion in rates was delayed by the Electricity Pricing, Conservation and Supply Act, 2002. These distribution regulatory assets were expected to be recovered in rates over a four year period, commencing April 1, 2004. All amounts to be recovered including the pre-market opening energy variance (PMOEV) and qualifying market transition costs (QMTC), however, were to be subject to a future OEB review. The Company applied for and received final OEB approval to recover market opening costs as part of its May 1, 2006 rate application.

Retail settlement variances
The Company accounts for differences between amounts charged by a) the Independent Electricity System Operator (IESO) for energy commodity costs, costs of market operation, wholesale market settlement charges and b) Hydro One for transmission charges and the amounts billed to customers by the Company based on the OEB approved rates in retail settlement variance accounts.

Other regulatory assets and liabilities
These accounts include certain amounts deferred as required by the OEB Distribution Rate Handbook including smart meter expenditures and cost recoveries, certain OEB cost assessments and OMERS pension expenditures.

6. Employee future benefits

Pension plan
Current service contributions to OMERS for 2007 were $156 (2006 - $151).

Employee future benefits other than pension plan
The Company measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at December 31, 2006. Key economic assumptions used to determine the valuation are Consumer Price Index; 2% per annum, discount rate; 5% per annum and salary increase rate; 3.3%. A reconciliation of the Company's accrued benefits obligation is as follows:

	2007	2006
Employee future benefits obligation, beginning of year	$ 608	$ 630
Current service cost	5	4
Interest on benefits obligation	48	42
Benefit plan payments	(64)	(68)
Employee future benefits obligation, end of year	$ 597	$ 608

(In Thousands)

7. Long term debt

The promissory note payable to the City of Orillia, the shareholder of Orillia Power Corporation, the parent Company, bears interest for the current year at 6.25% per annum (2006 – 6.25%). The interest rate is reviewed annually. Payments of interest are required to be made quarterly on the last day of March, June, September and December. The promissory note is due December 31, 2030.

8. Capital stock

	2007	2006
Authorized:		
The Company is authorized to issue an unlimited number of common shares.		
Issued:		
1,001 shares	**$ 8,236**	$ 8,236

9. Commitments

IESO prudential security
Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO), are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by default notice issued by the IESO. As at December 31, 2007, the Company has provided prudential support to the IESO in the form of a bank letter of credit in the amount of $1,388 (2006 - $1,933).

Capital expenditure
The Company anticipates taking delivery in 2008 of a front centre mount radial boom derrick manufactured to Orillia Power specifications at a cost of $428.

10. Contingent liability

A class action lawsuit has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties on overdue utility bills at any time after April 1, 1981. The claim is that the penalties were charged at rates which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, however the Court did not permit the plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court. In 2007, Enbridge filed an application to the Ontario Energy Board ("OEB") to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDC's situation may be distinguishable from that of Consumers Gas. At this time it is not possible to quantify the effect, if any, on the financial statements of the Company.

(In Thousands)

11. Payments in lieu of taxes

The provision for payments in lieu of corporate income taxes (PILS) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory rate and effective tax rates is provided as follows:

	2007	2006
Earnings before provision for PILS	**$ 1,120**	$ 3,261
Federal and Ontario statutory income tax rates	**36.1%**	36.1%
Provision for PILS at statutory rate	**$ 404**	$ 1,178
Increase (decrease) resulting from:		
Temporary differences		
Amortization in excess of capital cost allowance	**136**	181
Contingent liabilities	**(4)**	(8)
Regulatory asset adjustment	**81**	(646)
Adjustment to prior year provision	**(2)**	24
Net temporary differences	**211**	(449)
Permanent differences		
Capital cost allowance on appraisal increment	**(43)**	(45)
Dividend refund	**(93)**	13
Other	**(2)**	3
Net permanent differences	**(138)**	(29)
Provision for PILS	**$ 477**	$ 700
Effective income tax rate	**42.6%**	21.5%

Future income taxes have not been recorded, as they are expected to be reflected through future rates. Significant components of the company's deductible timing differences are as follows:

	2007	2006
Employee future benefits	**$ 55**	$ 66
Regulatory assets and liabilities	**295**	68
Property and equipment	**4,480**	4,379
	$ 4,830	$ 4,513

(In Thousands)

12. Supplemental cash flow information

		2007		2006
Change in non-cash operating working capital				
Receivables	$	(225)	$	393
Unbilled revenue		24		390
Inventory		(1)		(15)
Prepaids		(29)		37
Due from related parties		1		(70)
Payables and accruals		(317)		(954)
Payments in lieu of taxes recoverable		(253)		(220)
Customer and retailer deposits		(149)		126
	$	(949)	$	(313)
Interest received	$	208	$	198
Interest paid	$	610	$	640
Payment in lieu of taxes paid	$	738	$	926

13. Public liability insurance

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE), which was created on January 1, 1987. A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other through the same attorney. MEARIE provides general liability insurance to the Company of $30 million per occurrence.

14. Financial instruments

The Company's financial instruments consist of cash, receivables, payables and accruals, unbilled revenue, payments in lieu of taxes recoverable, regulatory assets and liabilities, amounts due from related parties customer and retailer deposits and long-term debt. Unless otherwise noted, it is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair value of these financial instruments approximates their carrying values, unless otherwise noted.

15. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for the current year.

16. Future accounting pronouncements

Accounting pronouncements that will come into effect during 2008 and 2009 are listed below. The Company is currently assessing the potential impact that each of the following new standards will have on its financial statements.

Financial instruments, hedges, and comprehensive income

Effective January 1, 2008, the Company will be required to adopt CICA Handbook Section 3855, "Financial Instruments - Recognition and Measurement"; Section 3865 "Hedges"; and Section 1530 "Comprehensive Income". Under the new standards, all financial assets must be classified as held-to-maturity, loans and receivables, held-for-trading or available-for-sale and all financial liabilities must be classified as held-for-trading and other. Financial instruments classified as held-for-trading will be measured at fair value with changes in fair value recognized in net income. Financial assets classified as held-to-maturity or as loans and receivables and financial liabilities not classified as held-for-trading will be measured at amortized cost. Available-for-sale financial assets will be measured at fair value with changes in fair value recognized in other comprehensive income. All derivative financial instruments will be reported on the balance sheet at fair value with changes in fair value recognized in net income unless the derivative is part of a hedging relationship. The new standards will also require presentation of a separate statement of comprehensive income.

Financial instruments disclosures and presentation

Effective January 1, 2008, the Company will be required to adopt CICA Handbook Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation" which will replace Section 3861, Financial Instruments – Disclosure and Presentation. The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how these risks are managed. The presentation standard carries forward former presentation requirements that are unchanged.

Capital disclosures

Effective January 1, 2008, the Company will be required to adopt CICA Handbook Section 1535 "Capital Disclosures". The new standard requires disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital and whether the entity has complied with any capital requirements and, if it has not complied, the consequences of such non-compliance.

16. Future accounting pronouncements (Continued)

Inventories

Effective January 1, 2008, the Company will be required to adopt CICA Handbook Section 3031 "Inventories". This new standard replaces the existing Section 3030 of the same name and contains requirements on measurement and disclosure of inventories and revises and enhances the requirements for assigning costs to inventories. This new standard also allows for reversal of previous write-downs.

General standards on financial statement presentation

Effective January 1, 2008, the Company will be required to adopt CICA Handbook Section 1400 "General Standards on Financial Statement Presentation". This new standard amends the previous standard to include requirements to assess and disclose an entity's ability to continue as a going concern.

Rate regulated operations

Effective January 1, 2009, the Company will be required to adopt changes to the CICA Handbook regarding rate regulated operations. The temporary exemption of Section 1100 that provided relief from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation will be removed. Section 3465 will be amended to require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers.

There will be adjustments within AcG-19 to reflect the changes made for Sections 1100 and 3465 of the CICA Handbook.

APPENDIX 1 – M

OPDC's Audited Financial Statements with audit opinion attached for the year ended December 31, 2008 follows on the next nineteen pages.

Orillia Power Distribution Corporation

Financial Statements

December 31, 2008

ORILLIAPOWER

Energizing Our Community

Contents

Grant Thornton

Auditors' Report

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To the Directors of

Orillia Power Corporation

We have audited the balance sheet of Orillia Power Distribution Corporation as at December 31, 2008 and the statements of earnings and deficit 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 cash flows for year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Ontario
March 16, 2009

Chartered Accountants
Licensed Public Accountants

Orillia Power Distribution Corporation
Statements of Earnings and Deficit

(In Thousands)

Year Ended December 31	2008	2007
Revenue		
Sale of power	$ 22,791	$ 23,391
Distribution	6,241	6,201
Other	600	498
	29,632	30,090
Costs		
Power purchased	22,791	23,391
Operations, maintenance and administration	3,878	3,857
Amortization	1,409	1,320
	28,078	28,568
Earnings from operations	1,554	1,522
Interest income	131	208
Interest on long term debt (Note 3)	(610)	(610)
Earnings before payments in lieu of taxes	1,075	1,120
Payments in lieu of taxes (Note 12)	473	477
Net earnings	$ 602	$ 643
Retained earnings, beginning of year	$ 245	$ 1,102
Net earnings	602	643
Dividends	(4,000)	(1,500)
(Deficit), retained earnings, end of year	$ (3,153)	$ 245

See accompanying notes to the financial statements.

Orillia Power Distribution Corporation
Balance Sheet

(In Thousands)

December 31		2008		2007
Assets				
Current				
Cash	$	844	$	3,708
Receivables		1,817		2,471
Unbilled revenue		3,515		3,396
Payments in lieu of taxes recoverable		58		166
Inventory (Note 6)		484		449
Prepaids		76		60
Due from related parties (Note 3)		500		525
		7,294		10,775
Property and equipment (Note 4)		15,887		15,044
Regulatory assets (Note 5)		-		155
	$	23,181	$	25,974
Liabilities				
Current				
Payables and accruals	$	4,329	$	3,784
Customer and retailer deposits		558		591
Employee future benefits (Note 7)		575		597
Regulatory liabilities (Note 5)		523		408
Long term debt (Note 8)		9,762		9,762
		15,747		15,142
Shareholder's Equity				
Capital stock (Note 9)		8,236		8,236
Contributed capital		2,351		2,351
(Deficit) retained earnings		(3,153)		245
		7,434		10,832
	$	23,181	$	25,974

Commitments and contingent liability (Note 10 and 11)

On Behalf of the Board

_______________ Director _______________ Director

See accompanying notes to the financial statements.

Orillia Power Distribution Corporation
Statement of Cash Flows

(In Thousands)

Year Ended December 31	2008	2007
Increase (decrease) in cash and cash equivalents		
Operating		
Net earnings	$ 602	$ 643
Amortization	1,409	1,320
Employee future benefits	(22)	(11)
	1,989	1,952
Change in non-cash operating working capital (Note 13)	1,129	(949)
	3,118	1,003
Financing		
Dividends	(4,000)	(1,500)
Investing		
Net reduction in regulatory assets	155	307
Net addition (reduction) in regulatory liabilities	115	(79)
Net additions to property and equipment	(2,252)	(1,157)
	(1,982)	(929)
Net decrease in cash and cash equivalents	(2,864)	(1,426)
Cash and cash equivalents, beginning of year	3,708	5,134
Cash and cash equivalents, end of year	$ 844	$ 3,708

See accompanying notes to the financial statements.

1. Nature of operations

The Company distributes electricity to the residents and businesses in the City of Orillia, under a license granted by the Ontario Energy Board (OEB). The Company is regulated by the OEB under the authority of the Ontario Energy Board Act, 1998. The OEB prescribes license requirements and conditions to electricity distributors, which may include among other things, specified accounting records, regulatory accounting principles, separation of accounts for distinct businesses and guidelines for establishing just and reasonable rates.

2. Summary of significant accounting policies

Cash and cash equivalents

Cash and cash equivalents include cash on hand and balances with banks.

Inventory

Inventory consists of repair parts, supplies and materials for maintenance and future capital expansion. The inventory is measured at the lower of the weighted average cost of similar items and net realizable value. Cost includes all acquisition costs incurred in bringing inventory to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory.

Rate regulation

The rates of the Company's electricity distribution business are subject to regulation by the Ontario Energy Board (OEB), under the authority granted by the Ontario Energy Board Act (1998). The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity, ensuring continued rate protection for rural and remote electricity consumers, and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. This change in timing gives rise to the recognition of regulatory assets and liabilities. These regulatory assets and liabilities reflect the fact that revenue and expenses are recognized in the financial statements in different periods consistent with their inclusion in rates, as directed by the regulator, than would be the case for an enterprise that is unregulated. Specific regulatory assets and liabilities recognized at December 31, 2008 are disclosed in Note 5. In the absence of rate regulation, regulated assets and liabilities would be recognized in earnings in the period to which they relate.

2. Summary of significant accounting policies (Continued)

Rate regulation (Continued)

The Company continually assesses the likelihood of recovery of each of its regulatory assets and believes that it is probable that its regulatory assets and liabilities will be factored into the setting of future rates. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Revenue recognition

The sale of power and distribution revenue attributable to the delivery of electricity to customers is recorded on the basis of regular meter readings using rates approved by the Ontario Energy Board and is recognized in the period that power is consumed. Customer usage since the date of the last meter reading to year end is estimated as unbilled revenue. Other revenue and interest income are recognized when earned.

Property and equipment

Property and equipment are recorded at cost and include contracted services, materials, labour, engineering costs and overheads. Significant renewals and enhancements to existing assets are capitalized only if the service life of the asset is extended, reliability or productivity is improved above original design standards or associated operating costs are lowered. Maintenance and repair costs are expensed as incurred.

Property and equipment is amortized using the straight-line method over periods approximating its estimated useful life as follows:

Land rights	5	years
Buildings	10-30	years
Sub-stations/sub-transmission lines	25-35	years
Distribution system	25-35	years
Other capital assets	5-10	years

When property and equipment is sold or scrapped, the cost of the asset and the related accumulated amortization is removed when identifiable from the accounts, with the resulting net gain or loss being included in operations for the year.

Fixed assets retirement obligations

Canadian generally accepted accounting principles (GAAP) require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated fixed assets.

2. Summary of significant accounting policies (Continued)

Fixed assets retirement obligations (Continued)

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its fixed assets for an indefinite period, no removal date can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations can not be made at the balance sheet date.

Corporate income and capital taxes

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

The Company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the Company at that time. This regulation accounting treatment differs from Canadian generally accepted accounting principles for enterprises operating in a non-regulated environment.

Impairment of long-lived assets

Long-lived assets are tested for impairment when events or changes in circumstances indicate that their carrying amounts may not be recoverable. When indicators of impairment of the carrying value of the long-lived assets exist and the carrying value is greater than the fair value, an impairment loss is recognized to the extent that the fair value is below the carrying value. It is management's opinion that the long-lived assets are not exposed to any impairment and no impairment losses have been recognized.

Employee future benefits

Pension plan
The Company provides pension benefits for its employees through the Ontario Municipal Employees Retirement System (OMERS). This multi-employer pension plan provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. It is a contributory defined benefit pension plan financed by equal contributions from participating employers and employees and by investment earnings of the fund. The Company recognizes the expense related to this plan as contributions are made.

2. Summary of significant accounting policies (Continued)

Employee future benefits (Continued)

Employee future benefits other than pension plan
The Company provides life insurance benefits to employees hired prior to January 1, 2008 when they are no longer providing active service. The Company is also obligated to provide certain medical and dental benefits to age 65 under an early retirement plan for a limited number of former employees. Employee future benefits expense is recognized in the period in which the employee renders services. Employee future benefits other than pension plans are recorded on an accrual basis. The accrued benefit obligation and current service costs are actuarially determined using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the present value of expected future benefits attributed to employee's services rendered in the period.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. These estimates and assumptions are based on management's historical experience, best knowledge of current events and actions that the Company may undertake in the future. Significant accounting estimates include allowance for doubtful accounts, unbilled revenue, inventory obsolescence, estimated useful lives of property and equipment, accrued benefit obligations and remaining recovery (settlement) period for regulated assets (liabilities). Actual results could differ from those estimates.

Financial instruments, hedges, and comprehensive income

The Company has made the following classifications for the purpose of measuring the value of the financial instruments:

- Cash and cash equivalents have been classified as "held for trading". They are initially measured at fair market value and the gains and losses resulting from the revaluation at fair value at the end of each period are recognized in net earnings.
- Receivables are classified as "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of accounts receivable are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.
- Payables and accruals, customer and retailer deposits and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in earnings.

Unless otherwise noted, it is management's opinion that they are not exposed to significant interest, currency or credit risks arising from its financial instruments.

(In Thousands)

3. Related party transactions

Transactions involving the sale of electricity are in the normal course of operations and are measured at the exchange amount, which is equal to the fair value as prescribed by regulation. Transactions involving other services have been recorded in these financial statements at the carrying amounts, which were equal to historical cost or fair value. Fair values represent fees for equivalent services provided to third parties in the normal course of operations as prescribed by regulations. The Company had the following related party transactions

		2008		2007
Orillia Power Generation Corporation - a company under common control				
Services purchased	**$**	**308**	$	248
Power purchased on behalf of Orillia customers		**1,052**		758
Services provided		**846**		819
City of Orillia - the shareholder of Orillia Power Corporation, the parent company				
Power sold		**1,214**		1,277
Other services sold		**114**		79
Purchases		**125**		97
Property taxes		**70**		64
Interest paid		**610**		610
Orillia Power Corporation - parent company				
Dividend paid		**4,000**		1,500
Administrative services provided		**8**		9
Balances outstanding at December 31:				
Due from Orillia Power Generation Corporation - related company	**$**	**500**	$	525

During the year, the Company paid interest of $610 (2007 - $610) on a promissory note payable, to the City of Orillia, the shareholder of Orillia Power Corporation, the parent Company. Included in payables and accruals is $182 (2007 - $174) due to the City of Orillia. Included in receivables is $106 (2007 - $47) due from the City of Orillia.

(In Thousands)

4. Property and equipment

				2008	2007
	Cost	Accumulated Amortization		**Net Book Value**	Net Book Value
Land	$ 210	$ -		**$ 210**	$ 206
Land rights	37	27		**10**	7
Buildings	1,445	713		**732**	563
Sub-stations/sub-transmission lines	10,319	3,860		**6,459**	5,941
Distribution system	17,355	9,955		**7,400**	7,744
Other capital assets	4,092	3,016		**1,076**	583
	$ 33,458	$ 17,571		**$ 15,887**	$ 15,044

5. Regulatory assets and liabilities

As described in Note 2, the Company has recorded the following regulatory assets and liabilities:

	2008	2007
Regulatory assets		
Other regulatory assets	**$ -**	$ 155
	$ -	$ 155
Regulatory liabilities		
Retail settlement variances	**$ 491**	$ 406
Other regulatory liabilities	**32**	2
	$ 523	$ 408

Retail settlement variances
The Company accounts for differences between amounts charged by the Independent Electricity System Operator (energy commodity costs, costs of market operation, wholesale market settlement charges) and Hydro One (transmission charges) and the amounts billed to customers by the Company based on the OEB approved rates in retail settlement variance accounts.

Other regulatory assets and liabilities
These accounts include certain amounts deferred as required by the OEB Distribution Rate Handbook including smart meter expenditures and cost recoveries, certain OEB cost assessments and OMERS pension expenditures. Cost recoveries exceeded expenditures in 2008 resulting in a regulatory liability of $32 (2007 – regulatory asset $155).

In the absence of rate regulation, the net effect on earnings would be an increase of $270 (2007 - $228).

(In Thousands)

6. Inventory

		2008		2007
Opening Balance	$	**449**	$	448
Inventory purchased		**573**		469
Inventory used in capital projects (capitalized)		**(269)**		(284)
Inventory used in operations & maintenance (expensed)		**(271)**		(182)
Inventory adjustment		**2**		(2)
Closing balance	$	**484**	$	449

7. Employee future benefits

Pension plan
Current service contributions to OMERS for 2008 were $164 (2007 - $156).

Employee future benefits other than pension plan
The Company measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at December 31, 2006. Key economic assumptions used to determine the valuation are Consumer Price Index; 2% per annum, discount rate; 5% per annum and salary increase rate; 3.3%. A reconciliation of the Company's accrued benefits obligation is as follows:

		2008		2007
Employee future benefits obligation, beginning of year	$	**597**	$	608
Current service cost		**5**		5
Interest on benefits obligation		**30**		48
Benefit plan payments		**(57)**		(64)
Employee future benefits obligation, end of year	$	**575**	$	597

(In Thousands)

8. Long term debt

The promissory note payable to the City of Orillia, the shareholder of Orillia Power Corporation, the parent Company, bears interest for the current year at 6.25% per annum (2007 – 6.25%). The interest rate is reviewed annually. Payments of interest are required to be made quarterly on the last day of March, June, September and December. The promissory note is due December 31, 2030.

9. Capital stock

	2008	2007
Authorized:		
The Company is authorized to issue an unlimited number of common shares.		
Issued:		
1,001 common shares	**$ 8,236**	$ 8,236

10. Commitments

IESO prudential security
Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO), are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by default notice issued by the IESO. As at December 31, 2008, the Company has provided prudential support to the IESO in the form of a bank letter of credit in the amount of $1,388 (2007 - $1,388).

Smart meters
The provincial government requires all electrical distributors in the province to install smart meters on customer premises by December 31, 2010. Smart meters allow for the monitoring of electricity consumption by time of use and will, in the future, allow for varying electricity commodity rates according to the customer's consumption patterns. In accordance with its electrical distributors licence, Orillia Power Distribution Corporation is required to install these meters and will commence installation in fiscal 2009, with the expectation of completion by the end of the year. The total cost of the project is estimated at approximately $3,000. The Company anticipates arranging financing to cover the cost of this project and to recover these costs through future rate adjustments charged to customers.

11. Contingent liability

A class action lawsuit has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties on overdue utility bills at any time after April 1, 1981 (the Griffith's Action). The claim is that the penalties were charged at rates which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Enbridge case rejecting all of the defences which had been raised by Enbridge, however the Court did not permit the plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court. In 2007, Enbridge filed an application to the Ontario Energy Board ("OEB") to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period. On February 10, 2009 the Superior Court of Justice approved a settlement agreement related to the class action against Union Gas, similar to the Enbridge decision.

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 LDC's situation may be distinguishable from that of Consumers Gas. At this time it is not possible to quantify the effect, if any, on the financial statements of the Company. Management does not believe that any adjustment would have a material impact on the financial statements.

(In Thousands)

12. Payments in lieu of taxes

The provision for payments in lieu of corporate income taxes (PILS) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory rate and effective tax rates is provided as follows:

	2008	2007
Earnings before provision for PILS	$ 1,075	$ 1,120
Federal and Ontario statutory income tax rates	33.5%	36.1%
Provision for PILS at statutory rate	$ 360	$ 404
Increase (decrease) resulting from:		
Temporary differences		
Amortization in excess of capital cost allowance	84	136
Contingent liabilities	(7)	(4)
Regulatory asset adjustment	93	81
Adjustment to prior year provision	10	(2)
Net temporary differences	180	211
Permanent differences		
Capital cost allowance on appraisal increment	(39)	(43)
Dividend refund	(26)	(93)
Other	(2)	(2)
Net permanent differences	(67)	(138)
Provision for PILS	$ 473	$ 477
Effective income tax rate	44.0%	42.6%

Future income taxes have not been recorded, as they are expected to be reflected through future rates. Significant components of the Company's deductible timing differences are as follows:

	2008	2007
Employee future benefits	$ 33	$ 55
Regulatory assets and liabilities	528	295
Property and equipment	5,109	4,480
	$ 5,670	$ 4,830

(In Thousands)

13. Supplemental cash flow information

		2008		2007
Change in non-cash operating working capital				
Receivables	$	654	$	(225)
Unbilled revenue		(119)		24
Inventory		(35)		(1)
Prepaids		(16)		(29)
Due from related parties		25		1
Payables and accruals		545		(317)
Payments in lieu of taxes recoverable (payable)		108		(253)
Customer and retailer deposits		(33)		(149)
	$	1,129	$	(949)
Interest received	$	131	$	208
Interest paid	$	610	$	610
Payment in lieu of taxes paid (net)	$	396	$	738

14. Public liability insurance

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE), which was created on January 1, 1987. A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other through the same attorney. MEARIE provides general liability insurance to the Company of $30 million per occurrence.

15. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for the current year.

16. Capital disclosures

The Company's objectives when managing capital are:

- to safeguard the entity's ability to continue as a going concern, so that it can continue to provide adequate returns for shareholders and benefits for other stakeholders, and
- to provide an adequate return to shareholders by controlling costs and establishing rates that maximize rate of return commensurate with the level of risk.

The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions, annual profitability and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure the Company will adjust the amount of dividends paid to shareholders. The Company is not subject to any externally imposed capital requirements.

Consistently with others in the industry, the Company monitors capital on the basis of the debt-to-capital ratio. This ratio is calculated as long term debt divided by (long term debt plus equity) as shown on the balance sheet. Equity consists of share capital, contributed capital and retained earnings. The debit- to-capital ratio at December 31, 2008 is 57% (2007 - 47%).

17. Change in accounting policies

Accounting pronouncements that came into effect in 2008 along with the Company's approach to addressing the financial statement impact of each of the new standards is reviewed below.

Inventories

On January 1, 2008, the Company retroactively adopted, without restatement of prior periods, the recommendations included in the CICA Handbook Section 3031 "Inventories".

Section 3031 replaces the existing Section 3030 of the same name and contains requirements on measurement and disclosure of inventories and revises and enhances the requirements for assigning costs to inventories. This new standard also allows for reversal of previous write-downs. The Company's newly expanded disclosure is included in Note 2.

The Company has included a note to the financial statements (Note 6) that details the following: opening inventory, total inventory purchased, expensed, capitalized and written off during the year, and year end inventory value, tied to the financial statements.

The adoption of this standard had no impact on the results of operation or measurement of inventory. During the year, there were no write downs of inventory as a result of net realizable value being lower than cost and no inventory write downs recognized in previous yeears were reversed.

17. Change in accounting policies (Continued)

General standards of financial statement presentation

On January 1, 2008, the Company adopted CICA Handbook Section 1400 "General Standards of Financial Statement Presentation". This section requires that management make an assessment of the Company's ability to continue as a going concern over a period which is at least, but not limited to, twelve months from the balance sheet date. The adoption of this new requirement has not resulted in any additional disclosure.

Capital disclosures

On January 1, 2008, the Company adopted the recommendations included in the CICA Handbook Section 1535 "Capital Disclosures". The standard requires disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital and whether the entity has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. The adoption of this new accounting standard had no impact on net earnings. The Company's new disclosure is included in Note 16.

18. Future accounting pronouncements

Rate regulated operations

Effective January 1, 2009, the Company will be required to adopt changes to the CICA Handbook regarding rate regulated operations. The temporary exemption of Section 1100 that provided relief from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation will be removed.

Section 3465 will be amended to require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers.

There will be adjustments within AcG-19 to reflect the changes made for Sections 1100 and 3465 of the CICA Handbook.

International Financial Reporting Standards (IFRS)

The CICA has announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian generally accepted accounting principles, there will be some differences in accounting policies, that will need to be addressed. The Company is currently developing an implementation plan for the adoption of IFRS.

APPENDIX 1 – N

OPDC's Interim Financial Statements to June 30, 2009 follow on the next six pages.

ORILLIA POWER DISTRIBUTION CORPORATION

FINANCIAL STATEMENTS

June 30, 2009

INDEX

DISTRIBUTION CORPORATION

Energizing Our Community

ORILLIA POWER DISTRIBUTION CORPORATION

STATEMENT OF OPERATIONS - Actual vs. Budget

June 30, 2009

All Information Presented is Year To Date in $000's

	Actual YTD Jun-09	Budget YTD Jun-09	$ Variance	% Variance
Revenues				
Distribution	**3,185**	3,259	(74)	-2%
Other	**194**	186	8	4%
	3,379	3,445	(66)	-2%
Costs				
Operations & maintenance - distribution	**927**	938	(11)	-1%
Billing and collection	**553**	416	137	33%
Administration and general	**578**	586	(8)	-1%
Amortization	**725**	702	23	3%
	2,783	2,641	142	5%
EARNINGS FROM OPERATIONS	**596**	**804**	**(208)**	**-26%**
Interest income	**2**	8	(6)	-76%
Interest on long term debt	**(305)**	(305)	(0)	0%
Earnings before payment in lieu of taxes	**293**	508	(215)	-42%
Payments in lieu of taxes	**(117)**	(205)	88	-43%
NET EARNINGS	**176**	**303**	**(127)**	**-42%**

ORILLIA POWER DISTRIBUTION CORPORATION

STATEMENT OF OPERATIONS - Year End Expectation

June 30, 2009 *All Information Presented is Year To Date in $000's*	YEE Jun-09	2009 BUDGET	$ Variance (YEE - Bud)	% VARIANCE ($ Var) / Bud
Revenues				
Distribution	**6,164**	6,364	(200)	-3%
Other	**471**	459	12	3%
	6,635	6,823	(188)	-3%
Costs				
Operations & maintenance - distribution	**1,870**	1,870	0	0%
Billing and collection	**1,064**	914	150	16%
Administration and general	**1,232**	1,243	(11)	-1%
Amortization	**1,450**	1,427	23	2%
	5,616	5,454	162	3%
EARNINGS FROM OPERATIONS	**1,019**	**1,369**	**(350)**	**-26%**
Interest income	**7**	16	(9)	-56%
Interest on long term debt	**(610)**	(610)	0	0%
Earnings before payment in lieu of taxes	**416**	775	(359)	-46%
Payments in lieu of taxes	**(125)**	(279)	154	-55%
NET EARNINGS	**291**	**496**	**(205)**	**-41%**

ORILLIA POWER DISTRIBUTION CORPORATION

STATEMENT OF OPERATIONS

June 30, 2009

All Information Presented is Year To Date in $000's

	Jun-09	Jun-08	Jun-07	Jun-06
Revenues				
Sale of power	**12,389**	11,920	12,352	11,629
Distribution services	**3,185**	3,218	3,194	3,480
Other	**194**	259	216	163
	15,768	15,397	15,762	15,272
Costs				
Power purchased	**12,228**	11,426	11,986	11,388
Difference between power sold and purchased (RSVA)	**161**	494	366	241
Operations & maintenance	**927**	871	883	771
Billing and collection	**553**	397	413	486
Administration and general	**578**	585	561	483
Amortization	**725**	702	660	666
	15,172	14,475	14,869	14,035
EARNINGS FROM OPERATIONS	**596**	**922**	**893**	**1,237**
Interest income	**5**	85	111	87
Interest on regulatory assets and variances	**(3)**	1	(10)	(33)
Interest on long term debt	**(305)**	(305)	(305)	(305)
Earnings before payment in lieu of taxes	**293**	703	689	986
Payments in lieu of taxes*	**(117)**	(309)	(294)	(407)
NET EARNINGS	**176**	**394**	**395**	**579**
*Effective tax rate used to calculate provision	**40.0%**	44.0%	42.6%	41.3%

ORILLIA POWER DISTRIBUTION CORPORATION

BALANCE SHEET

June 30, 2009

All Information Presented is Year To Date in $000's

	Jun-09	Jun-08	Jun-07	Jun-06
Assets				
Current				
Cash and cash equivalents	**(18)**	5,020	4,270	4,873
Accounts receivable	**1,764**	1,280	1,512	1,705
Unbilled revenue	**747**	724	772	804
Inventory	**509**	468	490	435
Prepaids	**180**	19	8	8
Due from related parties	**270**	154	238	268
	3,452	7,665	7,290	8,093
Property and equipment				
Cost	**33,653**	37,451	36,445	35,252
Accumulated depreciation	**18,295**	22,585	21,243	20,281
	15,358	14,866	15,202	14,971
Other				
Regulatory assets	**123**	9	290	602
Retail settlement variances (RSVA)		66		
	123	75	290	602
TOTAL ASSETS	**18,933**	**22,606**	**22,782**	**23,666**
Liabilities				
Current				
Accounts payable and accrued liabilities	**1,023**	858	1,098	886
	1,023	858	1,098	886
Other				
Customer and retailer deposits	**679**	664	679	652
Employee future benefits	**575**	597	608	630
Regulatory liabilities			24	1,850
Retail settlement variances (RSVA)	**86**		27	178
	1,340	1,261	1,338	3,310
Promissory note due to the City of Orillia	**9,762**	9,762	9,762	9,762
Shareholder's Equity				
Contributed capital	**2,351**	2,351	2,351	2,351
Common shares issued and outstanding	**8,236**	8,236	8,236	8,236
Retained earnings	**(3,779)**	138	(3)	(879)
	6,808	10,725	10,584	9,708
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**18,933**	**22,606**	**22,782**	**23,666**

ORILLIA POWER DISTRIBUTION CORPORATION

STATEMENT OF CHANGES IN FINANCIAL POSITION

June 30, 2009

All Information Presented is Year To Date in $000's	**Jun-09**	**Jun-08**	**Jun-07**	**Jun-06**
NET INFLOW (OUTFLOW) OF CASH related to the following:				
Operating activities				
Net earnings (loss) for the year	**176**	394	395	579
Items not requiring funds				
Amortization	**725**	702	660	666
Change in non-cash operating working capital	**(208)**	1,568	500	(250)
	693	2,664	1,555	995
Financing activities				
Dividends	**(800)**	(500)	(1,500)	
	(800)	(500)	(1,500)	
Investing activities				
Net additions to property and equipment	**(195)**	(524)	(655)	(549)
Net reduction (addition) in regulatory assets	**(123)**	(326)	172	528
Net addition (reduction) in regulatory liabilities	**(437)**	(2)	(436)	(981)
	(755)	(852)	(919)	(1,002)
Net increase (decrease) in cash and cash equivalents	**(862)**	**1,312**	**(864)**	**(7)**
Cash position, beginning of year	**844**	3,708	5,134	4,880
CASH POSITION, end of period	**(18)**	5,020	4,270	4,873
Change in non-cash operating working capital				
Decrease (increase) in accounts receivable	**53**	1,191	734	938
Decrease (increase) in unbilled revenue	**2,768**	2,673	2,648	3,006
Decrease (increase) in stores inventory	**(25)**	(19)	(41)	(1)
Decrease (increase) in other current assets	**(46)**	207	23	60
Decrease (increase) in due from related parties	**229**	371	288	187
Increase (decrease) in accounts payable and accrued	**(3,309)**	(2,928)	(3,091)	(4,478)
Increase (decrease) in customer and retailer deposits	**122**	73	(61)	38
	(208)	1,568	500	(250)

APPENDIX 1 – O

Orillia Power Corporation’s 2008 shareholder presentation follows on the next seventeen pages.

Orillia Power Corporation

8th Annual Shareholder Meeting

April 20, 2009

Our agenda

- **Approval of 2008 Minutes**
- **Audited Consolidated Financial Statements Issued to Shareholder**
- **Chair's Report**
- **Shareholder Question Period**
- **Motion to Adjourn**

ORILLIAPOWER

Energizing Our Community

Our Mission

"Efficiently generate environmentally friendly energy and deliver energy cost effectively to our customers, the citizens of Orillia."

ORILLIAPOWER

Energizing Our Community

Key Areas to Measure Success

- **Safety of our staff and the public**
- **Environmental protection**
- **Reliability of supply**
- **1st class customer service**
- **Have a positive impact on the economic development and betterment of our community**
- **Create value for our shareholder and ensure long term growth and stability of the organization**

ORILLIAPOWER

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2008 was a Successful Year !

- Financial Results for the Shareholder
- Cost Efficient Delivery to Our Customers, and
- Service Levels

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Generation Revenues increased 50% from 2007 Levels !

- 52% increase in water flow production at all stations,

- 2% price decrease.

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2008 Financial Results

pg 2 Titled "Consolidated Statement of Earnings and Retained Earnings"

- **Total OPC Revenue including power sold to customers: $ 34.7 Million ; electricity costs + generation + distribution business revenues. ($33.5 million in 2007)**
- **OPC Direct Operating Expenditures: $ 6.42 Million ($6.1 million in 2007)**
- **Equivalent Corporate Provincial Tax: $ 1.0 Million ($585,000 in 2007)**
- **Net Earnings: $ 2.1 Million ($1.1 million in 2007)**

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2008 Financial Results

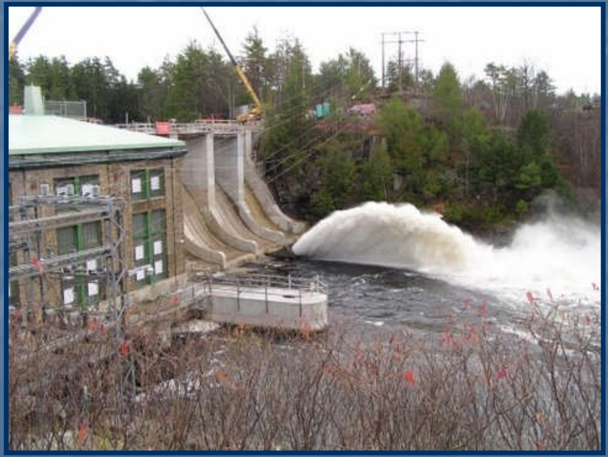
page 3 "Consolidated Balance Sheet"

Shareholder Equity: $ 15.8 Million

($15.2 million in 2007)

Assets Book Value: $ 37.5 Million

($36.5 Million in 2007)



ORILLIAPOWER

Energizing Our Community

Operations also got the job done!

Let's look at some of the 2008 results:

- ✓ **Completed <u>6th year</u> of lost time injury free work**
- ✓ **99.9 % distribution service reliability**
- ✓ **98.3 % of water flow capacity turned to electricity**
- ✓ **24.13 minutes average response time to electrical failures (provincial standard 60 minutes)**
- ✓ **100.0% of environmental & electrical safety requirements met**
- ✓ **Electrical Safety Authority Audit of our distribution system : no deficiencies & no areas in need of improvement - one of the <u>best</u> provincial audit results!**

ORILLIAPOWER

Energizing Our Community

Many Years of Orillia Community Benefits thru the Orillia Shareholder

- As of tonight, OPC will have provided since its year 2000 incorporation:
  - **$ 24.2 Million** in interest and dividends (including tonight's proposal)
  - **$ 1.5 Million** directly to the hospital building fund

ORILLIAPOWER

Energizing Our Community

Orillia Soldier's Memorial Hospital Foundation support PLUS

- **OPC support of community projects, such as :**
  - **Habitat for Humanity initiative**
  - **Orillia YMCA**
  - **Places for People project**
  - **Children's Safety Village Project**
  - **Local Salvation Army**
  - **Festival of Lights**
  - **Annual secondary school awards and scholarships for Georgian College and Lakehead University**
  - **Other charities – Cancer Society, Heart & Stroke, Big Brothers/Big Sisters, Easter Seals, Canada Day Festivities, Rotary Festival of Trees, Sharing Place Food Bank, Guardian Angels Food Bank, Couchiching Conservancy,**

    Crime Stoppers, etc.

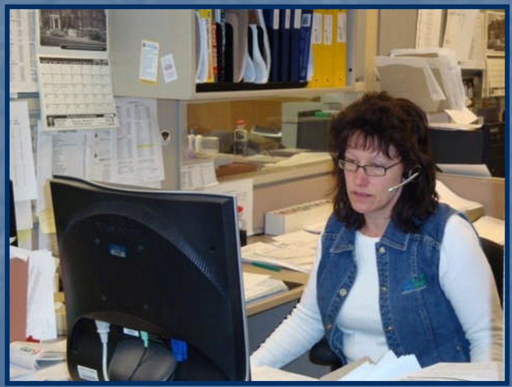
OPP Lock It or Lose It

ORILLIAPOWER

Energizing Our Community

Orillia Power Customer bills are among the lowest in Ontario!

- **94% of residential rates in Ontario in 2008 are higher than those in Orillia !**
- **Our commercial customers see lower costs than the same business in most other locations**



ORILLIAPOWER

Energizing Our Community

OPC is Actively Involved in Energy Management

- **Great Refrigerator Roundup**
  - **444 appliances collected (our target was 248 units)**
- **Electricity Retrofit Incentive Program**
  - **Incentives for conservation in businesses – 3 commercial customer's applications approved**
- **Summer Sweepstakes Challenge**
  - **Incentive for residential consumers to reduce consumption by 10% during summer months – 250 customers signed up**
- **Electricity Retrofit Incentive Program Workshop – seminar provided for local businesses**
- **Participation in Ontario's second Energy Conservation Week (May 17-23)**
- **Participation in Blackout Day Challenge (August)**

ORILLIAPOWER
Energizing Our Community

Looking Ahead – More Challenges & Opportunities

- Installations for Provincial Smart Metering will be the last few months of 2009. The actual Time of Use program will be early 2011. Customer information programs will increase as the Province gets closer to implementation.

- Municipalities, universities, schools & hospitals (for accounts > 250,000 kWh/yr, & > 50 kW demand) will move off the regulated price plan on Nov 1 2009 (if they have not already done so).

- OPC will continue to explore additional generation opportunities, including possible upgrades to our existing plants.

ORILLIAPOWER
Energizing Our Community

Orilla Power Corporation recommends that an operating dividend of $ 1.5 Million be paid in 2009 to its sole shareholder, the City of Orillia.

This represents a balance in our desire to pass along the benefits of OPC , with our need to support future OPC capital expenditures .

ORILLIAPOWER

Energizing Our Community

Our Appreciation Goes to Many that help us in "Energizing our Community"!

- **The Board wishes to express its appreciation to the City of Orillia Council and city staff for their continued positive support.**

- **Our Board again thanks the OPC staff for their loyalty, dedication, hard work and overall care in serving Orillia customers.**

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ORILLIA POWER CORPORATION

QUESTIONS ?

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APPENDIX 1 – P

A copy of OPDC's revenue requirement work form (Appendix 2-T in Filing Guidelines) follows on the next ten pages.

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Orillia Power Distribution Corporation	(1)
File Number:	EB-2009-0273	
Rate Year:	2010	***Version:*** ***1.0***

Table of Content

Notes:

(1) Pale green cells represent inputs

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

REVENUE REQUIREMENT WORK FORM

Ontario

Name of LDC: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

	Data Input (1)				
	Application		**Adjustments**	**Per Board Decision**	
1 Rate Base					
Gross Fixed Assets (average)	$36,244,000	**(4)**		$36,244,000	
Accumulated Depreciation (average)	($19,712,500)	**(5)**		($19,712,500)	
Allowance for Working Capital:					
Controllable Expenses	$4,346,000	(6)		$4,346,000	
Cost of Power	$23,732,000			$23,732,000	
Working Capital Rate (%)	15.00%			15.00%	
2 Utility Income					
Operating Revenues:					
Distribution Revenue at Current Rates	$6,161,700				
Distribution Revenue at Proposed Rates	$7,116,900				
Other Revenue:					
Specific Service Charges	$68,300				
Late Payment Charges	$60,000				
Other Distribution Revenue	$445,000				
Other Income and Deductions	($32,000)				
Operating Expenses:					
OM+A Expenses	$4,282,000			$4,282,000	
Depreciation/Amortization	$1,449,000			$1,449,000	
Property taxes	$27,000			$27,000	
Capital taxes	$6,000				
Other expenses	$31,000			$31,000	
3 Taxes/PILs					
Taxable Income:					
Adjustments required to arrive at taxable income	$68,300	**(3)**			
Utility Income Taxes and Rates:					
Income taxes (not grossed up)	$214,099				
Income taxes (grossed up)	$302,400				
Capital Taxes	$6,000				
Federal tax (%)	18.00%				
Provincial tax (%)	11.20%				
Income Tax Credits					
4 Capitalization/Cost of Capital					
Capital Structure:					
Long-term debt Capitalization Ratio (%)	56.0%				
Short-term debt Capitalization Ratio (%)	4.0%	**(2)**			**(2)**
Common Equity Capitalization Ratio (%)	40.0%				
Prefered Shares Capitalization Ratio (%)					
				Capital Structure must total 100%	
Cost of Capital					
Long-term debt Cost Rate (%)	7.62%				
Short-term debt Cost Rate (%)	1.33%				
Common Equity Cost Rate (%)	8.01%				
Prefered Shares Cost Rate (%)					

Notes:

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

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$36,244,000	$ -	$36,244,000
2	Accumulated Depreciation (average)	(3)	($19,712,500)	$ -	($19,712,500)
3	Net Fixed Assets (average)	(3)	$16,531,500	$ -	$16,531,500
4	Allowance for Working Capital	(1)	$4,211,700	$ -	$4,211,700
5	**Total Rate Base**		$20,743,200	$ -	$20,743,200

	(1) Allowance for Working Capital - Derivation				
6	Controllable Expenses		$4,346,000	$ -	$4,346,000
7	Cost of Power		$23,732,000	$ -	$23,732,000
8	Working Capital Base		$28,078,000	$ -	$28,078,000
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$4,211,700	$ -	$4,211,700

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: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$36,244,000	$ -	$36,244,000
2	Accumulated Depreciation (average)	(3)	($19,712,500)	$ -	($19,712,500)
3	Net Fixed Assets (average)	(3)	$16,531,500	$ -	$16,531,500
4	Allowance for Working Capital	(1)	$4,211,700	$ -	$4,211,700
5	**Total Rate Base**		$20,743,200	$ -	$20,743,200

	(1) Allowance for Working Capital - Derivation				
6	Controllable Expenses		$4,346,000	$ -	$4,346,000
7	Cost of Power		$23,732,000	$ -	$23,732,000
8	Working Capital Base		$28,078,000	$ -	$28,078,000
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$4,211,700	$ -	$4,211,700

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: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$7,116,900	$ -	$7,116,900
2	Other Revenue	(1)	$541,300	$ -	$541,300
3	Total Operating Revenues		$7,658,200	$ -	$7,658,200
	Operating Expenses:				
4	OM+A Expenses		$4,282,000	$ -	$4,282,000
5	Depreciation/Amortization		$1,449,000	$ -	$1,449,000
6	Property taxes		$27,000	$ -	$27,000
7	Capital taxes		$6,000	$ -	$6,000
8	Other expense		$31,000	$ -	$31,000
9	Subtotal		$5,795,000	$ -	$5,795,000
10	Deemed Interest Expense		$896,189	$ -	$896,189
11	Total Expenses (lines 4 to 10)		$6,691,189	$ -	$6,691,189
12	**Utility income before income taxes**		$967,011	$ -	$967,011
13	Income taxes (grossed-up)		$302,400	$ -	$302,400
14	**Utility net income**		$664,611	$ -	$664,611

Notes

(1)

Other Revenues / Revenue Offsets	Application	Per Board Decision
Specific Service Charges	$68,300	$68,300
Late Payment Charges	$60,000	$60,000
Other Distribution Revenue	$445,000	$445,000
Other Income and Deductions	($32,000)	($32,000)
Total Revenue Offsets	$541,300	$541,300

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$664,612	$664,612
2	Adjustments required to arrive at taxable utility income	$68,300	$68,300
3	Taxable income	$732,912	$732,912
	Calculation of Utility income Taxes		
4	Income taxes	$214,099	$214,099
5	Capital taxes	$6,000	$6,000
6	Total taxes	$220,099	$220,099
7	Gross-up of Income Taxes	$88,301	$88,301
8	Grossed-up Income Taxes	$302,400	$302,400
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$308,400	$308,400
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	18.00%	18.00%
12	Provincial tax (%)	11.20%	11.20%
13	Total tax rate (%)	29.20%	29.20%

Notes

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Application				
	Debt				
1	Long-term Debt	56.00%	$11,616,192	7.62%	$885,154
2	Short-term Debt	4.00%	$829,728	1.33%	$11,035
3	**Total Debt**	60.00%	$12,445,920	7.20%	$896,189
	Equity				
4	Common Equity	40.00%	$8,297,280	8.01%	$664,612
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$8,297,280	8.01%	$664,612
7	**Total**	100%	$20,743,200	7.52%	$1,560,801
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$11,616,192	7.62%	$885,154
9	Short-term Debt	4.00%	$829,728	1.33%	$11,035
10	**Total Debt**	60.00%	$12,445,920	7.20%	$896,189
	Equity				
11	Common Equity	40.0%	$8,297,280	8.01%	$664,612
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$8,297,280	8.01%	$664,612
14	**Total**	100%	$20,743,200	7.52%	$1,560,801

Notes

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

REVENUE REQUIREMENT WORK FORM

Ontario

Name of LDC: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$955,076		$955,076
2	Distribution Revenue	$6,161,700	$6,161,824	$6,161,700	$6,161,824
3	Other Operating Revenue Offsets - net	$541,300	$541,300	$541,300	$541,300
4	**Total Revenue**	$6,703,000	$7,658,200	$6,703,000	$7,658,200
5	Operating Expenses	$5,795,000	$5,795,000	$5,795,000	$5,795,000
6	Deemed Interest Expense	$896,189	$896,189	$896,189	$896,189
	Total Cost and Expenses	$6,691,189	$6,691,189	$6,691,189	$6,691,189
7	**Utility Income Before Income Taxes**	$11,811	$967,011	$11,811	$967,011
8	Tax Adjustments to Accounting Income per 2009 PILs	$68,300	$68,300	$68,300	$68,300
9	**Taxable Income**	$80,111	$1,035,311	$80,111	$1,035,311
10	Income Tax Rate	29.20%	29.20%	29.20%	29.20%
11	**Income Tax on Taxable Income**	$23,392	$302,311	$23,392	$302,311
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	($11,582)	$664,611	($11,582)	$664,611
14	**Utility Rate Base**	$20,743,200	$20,743,200	$20,743,200	$20,743,200
	Deemed Equity Portion of Rate Base	$8,297,280	$8,297,280	$8,297,280	$8,297,280
15	Income/Equity Rate Base (%)	-0.14%	8.01%	-0.14%	8.01%
16	Target Return - Equity on Rate Base	8.01%	8.01%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-8.15%	0.00%	-8.15%	0.00%
17	Indicated Rate of Return	4.26%	7.52%	4.26%	7.52%
18	Requested Rate of Return on Rate Base	7.52%	7.52%	7.52%	7.52%
19	Sufficiency/Deficiency in Rate of Return	-3.26%	0.00%	-3.26%	0.00%
20	Target Return on Equity	$664,612	$664,612	$664,612	$664,612
21	Revenue Sufficiency/Deficiency	$676,194	($1)	$676,194	($1)
22	**Gross Revenue Sufficiency/Deficiency**	$955,076 **(1)**		$955,076 **(1)**	

Notes:

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

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

		Revenue Requirement		
Line No.	**Particulars**	**Application**	**Per Board Decision**	
1	OM&A Expenses	$4,282,000	$4,282,000	
2	Amortization/Depreciation	$1,449,000	$1,449,000	
3	Property Taxes	$27,000	$27,000	
4	Capital Taxes	$6,000	$6,000	
5	Income Taxes (Grossed up)	$302,400	$302,400	
6	Other Expenses	$31,000	$31,000	
7	Return			
	Deemed Interest Expense	$896,189	$896,189	
	Return on Deemed Equity	$664,612	$664,612	
8	Distribution Revenue Requirement before Revenues	$7,658,201	$7,658,201	
9	Distribution revenue	$7,116,900	$7,116,900	
10	Other revenue	$541,300	$541,300	
11	**Total revenue**	$7,658,200	$7,658,200	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($1) **(1)**	($1) **(1)**	

Notes

(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Name of LDC: Orillia Power Distribution Corporation
File Number: EB-2009-0273
Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order							
		Monthly Delivery Charge				Total Bill			
		Current	Per Draft Rate Order	Change $	Change %	Current	Per Draft Rate Order	Change $	Change %
Residential	**800 kWh/month**	$ 24.58	$ 27.05	$ 2.47	10.0%	$ 89.34	$ 93.16	$ 3.82	4.3%
GS < 50kW	**2000** kWh/month	$ 60.59	$ 67.29	$ 6.70	11.1%	$ 227.48	$ 237.73	$ 10.25	4.5%

Notes:

ORILLIAPOWER

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EXHIBIT 2 - RATE BASE

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

ORILLIAPOWER

Energizing Our Community

EXHIBIT 2 - TABLES

EXHIBIT 2 - APPENDICES

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.

Net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The OPDC rate base calculation excludes non-distribution assets (sentinel lights). Capital expenditures from 2004 through to 2010 included in OPDC rate base are summarized in Exhibit 2 Tab 4 Schedule 1. OPDC's capitalization policy and asset management plan are summarized in Exhibit 2 Tab 4 Schedules 2 and 3 respectively.

Controllable expenses include operations and maintenance, billing and collecting and administration expenses. Controllable expenses are analyzed in detail in Exhibit 4 and OPDC has elected to use the "15% allowance approach" summarized in the filing guidelines to determine the working capital component of the rate base in Table 2-1. A summary of 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 can be found in Table 2-2 below. Details of OPDC's calculation of its working capital allowance are provided at Exhibit 2, Tab 3, Schedule 1.

Table 2-1 summarizes OPDC's rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test. OPDC has calculated its 2010 rate base as $20,743,200.

Note: In all tables throughout this application, "2006 EDR" is meant to indicate figures that were obtained from the 2006 OEB approved rate application for rates effective May 1, 2006 (last rebasing application).

Table 2-1: Rate Base - SUMMARY

Description	2006 EDR OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
SUMMARY OF COMPONENTS FOR DEEMED RATE BASE CALCULATION						
Gross Property Plant and Equipment	32,038,900	35,658,600	36,802,100	33,441,500	35,387,000	37,101,000
Accumulated Amortization	17,445,800	20,466,000	21,764,000	17,559,300	18,988,000	20,437,000
Net Book Value of Total Property Plant & Equipment	**14,593,100**	**15,192,600**	**15,038,100**	**15,882,200**	**16,399,000**	**16,664,000**
(A) Average Net Book Value - LDC Operations	**14,593,100**	**15,131,100**	**15,115,400**	**15,460,200**	**16,140,600**	**16,531,500**
Working Capital Expenses	23,481,700	26,222,500	27,266,400	26,679,400	27,247,000	28,078,000
(B) Working Capital Allowance @ 15%	**3,522,300**	**3,933,400**	**4,090,000**	**4,001,900**	**4,087,100**	**4,211,700**
Rate Base (A) + (B)	**18,115,400**	**19,064,500**	**19,205,400**	**19,462,100**	**20,227,700**	**20,743,200**

Table 2-2: Working Capital Allowance Calculation - SUMMARY of Expenses Included

Description	2006 EDR OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
SUMMARY OF COMPONENTS FOR DEEMED WORKING CAPITAL CALCULATION						
Distribution Maintenance & Operations	1,087,100	1,454,900	1,620,400	1,693,000	1,695,000	1,823,000
Billing & Collections, Community Relations	950,100	919,300	972,300	927,400	1,110,000	1,062,000
Administration & General	1,167,500	1,233,100	1,282,500	1,268,100	1,400,000	1,461,000
Cost of Power	20,277,000	22,615,200	23,391,200	22,790,900	23,042,000	23,732,000
Components for Working Capital Calculatio	**23,481,700**	**26,222,500**	**27,266,400**	**26,679,400**	**27,247,000**	**28,078,000**
Working Capital Allowance @ 15%	**3,522,300**	**3,933,400**	**4,090,000**	**4,001,900**	**4,087,100**	**4,211,700**

The OPDC Distribution System:

Orillia Power Distribution Corporation (OPDC) owns and operates the electricity distribution system with the licensed territory of 27 square kilometers within the City of Orillia, serving approximately 12,800 customers. As of January 1, 2009, OPDC had approximately 245 kilometres of overhead circuits, 58 kilometres of underground circuits, 10 Distribution stations and 1,756 transformers operating within the system.

Power is supplied to OPDC from Hydro One's Orillia Transformer Station at 44kv (4 feeders; M1, M4, M7 & M8) and steps power down to its distribution voltages of 13.8kV and 4.16kV using 10 distribution stations (4 at13.8kV and 6 at 4.16kV).

OPDC monitors its distribution system through a control centre at its main office, utilizing a Supervisory Control and Data Acquisition ("SCADA") system. The control center is staffed twelve hours a day, seven days a week and is monitored after-hours through a paging and dial-in system as well as a third party call center.

OPDC owns and maintains approximately 12,800 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. OPDC is currently active in installing smart meters as part of the Province of Ontario's smart meter initiative.

In managing its distribution system assets, OPDC'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 OPDC'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. OPDC 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, OPDC reviews capital projects identified for potential implementation and prioritizes each project based on defined criteria on a relative basis. In addition to the capital needs of the network, OPDC provides for maintenance planning for the assets. As with the capital budget, detailed analysis and consideration is undertaken in order to develop a comprehensive operating budget. Further information on OPDC's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

RATE BASE VARIANCE ANALYSIS:

Table 2-3 sets out OPDC'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 associated variances between each of the years as follows:

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

OPDC offers the following comments in respect of the relevant variances identified in Table 2-3. In total, OPDC rate base has increased by 14.8% to $20,743,200 for 2010 Test from the 2006 OEB approved amount of $18,115,400.

Note 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 2010 test and 2006 OEB Approved spans a six-year period and the **14.8% increase in rate base has over six years represents an average increase of 2.4% per year**. The increases in the rate base are the result of increases in the two main components (average net book value and working capital allowance).

OPDC capital expenditures for 2005 through 2010 have exceeded amortization expense for the same period by an average of approximately $333,000 per year ($1,999,900 / 6) as noted in Table 2-3 below. OPDC has been required to accelerate capital expenditures over the last few years in order to replace aging assets. A detailed breakdown year over year of OPDC capital expenditures and the drivers for same is presented in Exhibit 2 Tab 4 Schedule 1.

The 15% working capital allowance on OPDC operations expenditures has increased by $689,400 over the same six year period or approximately $115,000 per year. Much of this increase can be attributed to the cost of power component of working capital which is projected to be $23,732,000 for 2010 Test compared to $20,277,000 for 2006 EDR. The difference in cost of power of $3,455,000 at 15% is $518,250 or 75% of the total increase in working capital allowance. The remaining $171,150 increase in working capital allowance is attributable to increases in controllable expenses over the last six years.

A detailed calculation of the working capital allowance can be found at Exhibit 2, Tab 3, Schedule 1. OPDC's detailed driver analysis of controllable expenses can be found in Exhibit 4 Tab 3.

Table 2-3: Rate Base Components - From 2006 EDR To 2010 Test With Variances

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
SUMMARY OF COMPONENTS FOR DEEMED RATE BASE CALCULATION						
Gross Property Plant and Equipment	32,038,900	35,658,600	36,802,100	33,441,500	35,387,000	37,101,000
Accumulated Amortization	17,445,800	20,466,000	21,764,000	17,559,300	18,988,000	20,437,000
Net Book Value of Total Property Plant & Equ	**14,593,100**	**15,192,600**	**15,038,100**	**15,882,200**	**16,399,000**	**16,664,000**
(A) Average Net Book Value - LDC Operations	**14,593,100**	**15,131,100**	**15,115,400**	**15,460,200**	**16,140,600**	**16,531,500**
Working Capital Expenses	23,481,700	26,222,500	27,266,400	26,679,400	27,247,000	28,078,000
(B) Working Capital Allowance @ 15%	**3,522,300**	**3,933,400**	**4,090,000**	**4,001,900**	**4,087,100**	**4,211,700**
Rate Base (A) + (B)	**18,115,400**	**19,064,500**	**19,205,400**	**19,462,100**	**20,227,700**	**20,743,200**

Description	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
SUMMARY OF COMPONENT VARIANCES FOR DEEMED RATE BASE CALCULATION					
Gross Property Plant and Equipment	3,619,700	1,143,500	(3,360,600)	1,945,500	1,714,000
Accumulated Amortization	3,020,200	1,298,000	(4,204,700)	1,428,700	1,449,000
Net Book Value of Total Property Plant & Equipment	**599,500**	**(154,500)**	**844,100**	**516,800**	**265,000**
(A) Average Net Book Value - LDC Operations	**538,000**	**(15,700)**	**344,800**	**680,400**	**390,900**
Working Capital Expenses	2,740,800	1,043,900	(587,000)	567,600	831,000
(B) Working Capital Allowance @ 15%	**411,100**	**156,600**	**(88,100)**	**85,200**	**124,600**
Rate Base (A) + (B)	**949,100**	**140,900**	**256,700**	**765,600**	**515,500**

CUMULATIVE INCREASE IN RATE BASE COMPONENTS FROM 2006 OEB APPROVED TO 2010 TEST					
Increase in NBV of PP&E from 2006 OEB approved	**599,500**	**583,800**	**928,600**	**1,609,000**	**1,999,900**
Increase in WC allowance from 2006 OEB approved	**411,100**	**567,700**	**479,600**	**564,800**	**689,400**
Increase in rate base from 2006 OEB approved	**1,010,600**	**1,151,500**	**1,408,200**	**2,173,800**	**2,689,300**
Percentage Inc. in rate base from 2006 OEB approved	**5.6%**	**6.4%**	**7.8%**	**12.0%**	**14.8%**

CONTINUITY SCHEDULES FOR PROPERTY PLANT AND EQUIPMENT (FIXED ASSETS)

Exhibit 2, Tab 2 Schedule 1 presents OPDC's fixed asset continuity schedules, first in summary form (Tables 2-4 to 2-8), and then in detail (Tables 2-9 to 2-13) by account for 2006 Actual through to 2010 Test.

Table 2-4: Fixed Asset Continuity Schedule - As of December 31, 2006 - SUMMARY

	2006 Cost				2006 Accumulated Depreciation				2006 NBV
Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Distribution station equipment	3,181,700	490,000		**3,671,700**	1,842,700	90,800		**1,933,500**	**1,738,200**
Poles and wires	16,177,600	815,900	73,500	**16,920,000**	7,351,800	662,700	53,300	**7,961,100**	**8,958,900**
Line transformers	4,060,800	7,100		**4,067,900**	2,130,200	158,500		**2,288,700**	**1,779,300**
Services and meters	4,027,700	150,700		**4,178,500**	2,428,900	140,800		**2,569,800**	**1,608,600**
Other general plant	7,122,900	89,100	391,700	**6,820,500**	5,747,600	303,400	337,900	**5,712,900**	**1,107,300**
TOTALS SUMMARY INFORMATION	**34,570,700**	**1,552,800**	**465,200**	**35,658,600**	**19,501,200**	**1,356,200**	**391,200**	**20,466,000**	**15,192,300**

Table 2-5: Fixed Asset Continuity Schedule - As of December 31, 2007 - SUMMARY

	2007 Cost				2007 Accumulated Depreciation				2007 NBV
Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Distribution station equipment	3,671,700	85,800		**3,757,500**	1,933,500	92,300		**2,025,800**	**1,731,700**
Poles and wires	16,920,000	873,400		**17,793,500**	7,961,100	686,000	(100)	**8,647,200**	**9,146,300**
Line transformers	4,067,900	9,100		**4,077,000**	2,288,700	158,900		**2,447,500**	**1,629,500**
Services and meters	4,178,500	36,500		**4,215,000**	2,569,800	140,100		**2,709,800**	**1,505,200**
Other general plant	6,820,500	158,800	20,100	**6,959,100**	5,712,900	240,800	20,100	**5,933,700**	**1,025,400**
TOTALS SUMMARY INFORMATION	**35,658,600**	**1,163,600**	**20,100**	**36,802,100**	**20,466,000**	**1,318,100**	**20,000**	**21,764,000**	**15,038,100**

Table 2-6: Fixed Asset Continuity Schedule - As of December 31, 2008 - SUMMARY

	2008 Cost				2008 Accumulated Depreciation				2008 NBV
Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Distribution station equipment	3,757,500	52,200	121,800	**3,687,900**	2,025,800	90,700	121,800	**1,994,700**	**1,693,200**
Poles and wires	17,793,500	1,050,300	2,075,100	**16,768,600**	8,647,200	682,600	2,075,100	**7,254,700**	**9,513,900**
Line transformers	4,077,000	68,900		**4,145,900**	2,447,500	161,600		**2,609,100**	**1,536,800**
Services and meters	4,215,000	57,000	829,200	**3,442,700**	2,709,800	137,500	829,200	**2,018,100**	**1,424,700**
Other general plant	6,959,100	1,023,200	2,586,100	**5,396,400**	5,933,700	334,800	2,586,100	**3,682,700**	**1,713,700**
TOTALS SUMMARY INFORMATION	**36,802,100**	**2,251,600**	**5,612,200**	**33,441,500**	**21,764,000**	**1,407,200**	**5,612,200**	**17,559,300**	**15,882,300**

Table 2-7: Fixed Asset Continuity Schedule - As of December 31, 2009 - SUMMARY

	2009 Cost				2009 Accumulated Depreciation				2009 NBV
Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Distribution station equipment	3,688,000	119,000		**3,807,000**	1,995,000	95,000		**2,090,000**	**1,717,000**
Poles and wires	16,768,000	1,198,000		**17,966,000**	7,255,000	693,000		**7,948,000**	**10,018,000**
Line transformers	4,146,000	55,000		**4,201,000**	2,609,000	161,000		**2,770,000**	**1,431,000**
Services and meters	3,442,000	69,000		**3,511,000**	2,018,000	130,000		**2,148,000**	**1,363,000**
Other general plant	5,397,000	505,000		**5,902,000**	3,682,000	350,000		**4,032,000**	**1,870,000**
TOTALS SUMMARY INFORMATION	**33,441,000**	**1,946,000**		**35,387,000**	**17,559,000**	**1,429,000**		**18,988,000**	**16,399,000**

Table 2-8: Fixed Asset Continuity Schedule - As of December 31, 2010 - SUMMARY

	2010 Cost				2010 Accumulated Depreciation				2010 NBV
Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
Distribution station equipment	3,807,000	109,000		**3,916,000**	2,090,000	93,000		**2,183,000**	**1,733,000**
Poles and wires	17,966,000	1,300,000		**19,266,000**	7,948,000	744,000		**8,692,000**	**10,574,000**
Line transformers	4,201,000	45,000		**4,246,000**	2,770,000	161,000		**2,931,000**	**1,315,000**
Services and meters	3,511,000	65,000		**3,576,000**	2,148,000	129,000		**2,277,000**	**1,299,000**
Other general plant	5,902,000	195,000		**6,097,000**	4,032,000	322,000		**4,354,000**	**1,743,000**
TOTALS SUMMARY INFORMATION	**35,387,000**	**1,714,000**		**37,101,000**	**18,988,000**	**1,449,000**		**20,437,000**	**16,664,000**

Table 2-9: Fixed Asset Continuity Schedule - As of December 31, 2006 - DETAIL

		2006 Cost				2006 Accumulated Depreciation				2006 NBV
Description		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land									
1806	Land Rights	24,900	500		**25,400**	19,400	1,900		**21,300**	**4,100**
1820	Distribution Station Equipment - Normally	3,181,700	490,000		**3,671,700**	1,842,700	90,800		**1,933,500**	**1,738,200**
1830	Poles, Towers and Fixtures	397,100			**397,100**					**397,100**
1835	Overhead Conductors and Devices	11,110,700	502,300	73,500	**11,539,600**	5,334,600	458,600	53,300	**5,739,900**	**5,799,700**
1840	Underground Conduit	4,669,800	313,600		**4,983,300**	2,017,200	204,100		**2,221,200**	**2,762,100**
1850	Line Transformers	4,060,800	7,100		**4,067,900**	2,130,200	158,500		**2,288,700**	**1,779,300**
1855	Services	2,063,100	106,600		**2,169,800**	1,169,300	81,500		**1,250,800**	**918,900**
1860	Meters	1,964,600	44,100		**2,008,700**	1,259,600	59,300		**1,319,000**	**689,700**
1905	Land	189,100			**189,100**					**189,100**
1908	Buildings and Fixtures	1,154,500	40,400		**1,194,900**	583,400	41,900		**625,300**	**569,600**
1915	Office Furniture and Equipment	379,600	17,000		**396,600**	324,100	20,000		**344,100**	**52,500**
1920	Computer Equipment - Hardware	571,300	11,700		**583,100**	508,200	22,600		**530,700**	**52,300**
1925	Computer Software	582,600	25,100		**607,700**	438,900	41,300		**480,100**	**127,500**
1930	Transportation Equipment	1,621,600	129,900	62,700	**1,688,900**	1,337,700	118,200	62,700	**1,393,300**	**295,600**
1935	Stores Equipment	35,600			**35,600**	21,100	2,900		**24,000**	**11,600**
1940	Tools, Shop and Garage Equipment	520,900	24,500		**545,400**	401,400	31,700		**433,100**	**112,200**
1960	Miscellaneous Equipment	329,000		329,000		265,300	10,000	275,200		
1980	System Supervisory Equipment	1,925,200			**1,925,200**	1,865,000	27,800		**1,892,800**	**32,400**
1985	Sentinel Lighting	131,700	(300)		**131,400**	113,400	2,900		**116,300**	**15,100**
1995	Contributions and Grants	(211,400)	(160,000)		**(371,400)**	(16,900)	(14,900)		**(31,800)**	**(339,600)**
TOTALS DETAILED GENERAL LEDGER		**34,702,400**	**1,552,500**	**465,200**	**35,790,000**	**19,614,600**	**1,359,100**	**391,200**	**20,582,300**	**15,207,400**
1985	Sentinel Lighting Non LDC	131,700	(300)		**131,400**	113,400	2,900		**116,300**	**15,100**
TOTALS DETAILED LDC		**34,570,700**	**1,552,800**	**465,200**	**35,658,600**	**19,501,200**	**1,356,200**	**391,200**	**20,466,000**	**15,192,300**

Table 2-10: Fixed Asset Continuity Schedule - As of December 31, 2007 - DETAIL

		2007 Cost				2007 Accumulated Depreciation				2007 NBV
Description		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land									
1806	Land Rights	25,400	5,500		**30,900**	21,300	2,400		**23,700**	**7,200**
1820	Distribution Station Equipment - Normally	3,671,700	85,800		**3,757,500**	1,933,500	92,300		**2,025,800**	**1,731,700**
1830	Poles, Towers and Fixtures	397,100	21,600		**418,700**					**418,700**
1835	Overhead Conductors and Devices	11,539,600	713,700		**12,253,300**	5,739,900	476,400	(100)	**6,216,400**	**6,036,900**
1840	Underground Conduit	4,983,300	138,100		**5,121,500**	2,221,200	209,600		**2,430,800**	**2,690,700**
1850	Line Transformers	4,067,900	9,100		**4,077,000**	2,288,700	158,900		**2,447,500**	**1,629,500**
1855	Services	2,169,800	28,400		**2,198,200**	1,250,800	80,400		**1,331,200**	**867,000**
1860	Meters	2,008,700	8,100		**2,016,800**	1,319,000	59,700		**1,378,600**	**638,200**
1905	Land	189,100	17,100		**206,200**					**206,200**
1908	Buildings and Fixtures	1,194,900	37,500		**1,232,400**	625,300	43,300		**668,600**	**563,800**
1915	Office Furniture and Equipment	396,600	3,200		**399,800**	344,100	17,300		**361,400**	**38,300**
1920	Computer Equipment - Hardware	583,100	12,600		**595,700**	530,700	20,800		**551,500**	**44,200**
1925	Computer Software	607,700	14,500		**622,200**	480,100	44,200		**524,300**	**97,900**
1930	Transportation Equipment	1,688,900	31,000	20,100	**1,699,800**	1,393,300	72,900	20,100	**1,446,100**	**253,700**
1935	Stores Equipment	35,600			**35,600**	24,000	2,900		**26,900**	**8,700**
1940	Tools, Shop and Garage Equipment	545,400	37,400		**582,700**	433,100	34,100		**467,200**	**115,500**
1960	Miscellaneous Equipment									
1980	System Supervisory Equipment	1,925,200			**1,925,200**	1,892,800	14,700		**1,907,500**	**17,700**
1985	Sentinel Lighting	131,400	1,700	7,900	**125,200**	116,300	2,100		**118,400**	**6,800**
1995	Contributions and Grants	(371,400)			**(371,400)**	(31,800)	(11,800)		**(43,500)**	**(327,800)**
TOTALS DETAILED GENERAL LEDGER		**35,790,000**	**1,165,300**	**28,000**	**36,927,300**	**20,582,300**	**1,320,200**	**20,000**	**21,882,400**	**15,044,900**
1985	Sentinel Lighting Non LDC	131,400	1,700	7,900	**125,200**	116,300	2,100		**118,400**	**6,800**
TOTALS DETAILED LDC		**35,658,600**	**1,163,600**	**20,100**	**36,802,100**	**20,466,000**	**1,318,100**	**20,000**	**21,764,000**	**15,038,100**

Table 2-11: Fixed Asset Continuity Schedule - As of December 31, 2008 - DETAIL

		2008 Cost				2008 Accumulated Depreciation				2008 NBV
Description		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land		74,100		**74,100**					**74,100**
1806	Land Rights	30,900	6,300		**37,300**	23,700	3,700		**27,400**	**9,800**
1820	Distribution Station Equipment - Normally	3,757,500	52,200	121,800	**3,687,900**	2,025,800	90,700	121,800	**1,994,700**	**1,693,200**
1830	Poles, Towers and Fixtures	418,700	(418,700)							
1835	Overhead Conductors and Devices	12,253,300	1,253,900	1,401,000	**12,106,200**	6,216,400	488,500	1,401,000	**5,303,900**	**6,802,300**
1840	Underground Conduit	5,121,500	215,100	674,100	**4,662,400**	2,430,800	194,100	674,100	**1,950,800**	**2,711,600**
1850	Line Transformers	4,077,000	68,900		**4,145,900**	2,447,500	161,600		**2,609,100**	**1,536,800**
1855	Services	2,198,200	31,700	410,500	**1,819,300**	1,331,200	76,800	410,500	**997,500**	**821,900**
1860	Meters	2,016,800	25,300	418,700	**1,623,400**	1,378,600	60,700	418,700	**1,020,600**	**602,800**
1905	Land	206,200	(70,500)		**135,700**					**135,700**
1908	Buildings and Fixtures	1,232,400	226,900	14,200	**1,445,100**	668,600	58,300	14,200	**712,700**	**732,400**
1915	Office Furniture and Equipment	399,800	1,600	357,700	**43,700**	361,400	16,400	357,700	**20,200**	**23,500**
1920	Computer Equipment - Hardware	595,700	6,800	504,600	**97,900**	551,500	19,900	504,600	**66,900**	**31,000**
1925	Computer Software	622,200	10,600	404,500	**228,300**	524,300	45,700	404,500	**165,500**	**62,900**
1930	Transportation Equipment	1,699,800	520,900	513,000	**1,707,700**	1,446,100	141,400	513,000	**1,074,500**	**633,200**
1935	Stores Equipment	35,600		6,600	**29,000**	26,900	2,900	6,600	**23,200**	**5,800**
1940	Tools, Shop and Garage Equipment	582,700	38,800	407,200	**214,400**	467,200	30,500	407,200	**90,600**	**123,800**
1960	Miscellaneous Equipment									
1980	System Supervisory Equipment	1,925,200	207,700	378,300	**1,754,600**	1,907,500	34,000	378,300	**1,563,200**	**191,400**
1985	Sentinel Lighting	125,200		109,000	**16,200**	118,400	1,800	109,000	**11,200**	**4,900**
1995	Contributions and Grants	(371,400)			**(371,400)**	(43,500)	(18,000)		**(61,500)**	**(309,900)**
TOTALS DETAILED GENERAL LEDGER		**36,927,300**	**2,251,600**	**5,721,200**	**33,457,700**	**21,882,400**	**1,409,000**	**5,721,200**	**17,570,500**	**15,887,200**
1985	Sentinel Lighting Non LDC	125,200		109,000	**16,200**	118,400	1,800	109,000	**11,200**	**4,900**
TOTALS DETAILED LDC		**36,802,100**	**2,251,600**	**5,612,200**	**33,441,500**	**21,764,000**	**1,407,200**	**5,612,200**	**17,559,300**	**15,882,300**

Table 2-12: Fixed Asset Continuity Schedule - As of December 31, 2009 - DETAIL

		2009 Cost				2009 Accumulated Depreciation				2009 NBV
Description		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	74,000	60,000		**134,000**					**134,000**
1806	Land Rights	37,000	8,000		**45,000**	27,000	4,000		**31,000**	**14,000**
1820	Distribution Station Equipment - Normally	3,688,000	119,000		**3,807,000**	1,995,000	95,000		**2,090,000**	**1,717,000**
1830	Poles, Towers and Fixtures									
1835	Overhead Conductors and Devices	12,106,000	988,000		**13,094,000**	5,304,000	496,000		**5,800,000**	**7,294,000**
1840	Underground Conduit	4,662,000	210,000		**4,872,000**	1,951,000	197,000		**2,148,000**	**2,724,000**
1850	Line Transformers	4,146,000	55,000		**4,201,000**	2,609,000	161,000		**2,770,000**	**1,431,000**
1855	Services	1,819,000	59,000		**1,878,000**	997,000	69,000		**1,066,000**	**812,000**
1860	Meters	1,623,000	10,000		**1,633,000**	1,021,000	61,000		**1,082,000**	**551,000**
1905	Land	136,000			**136,000**					**136,000**
1908	Buildings and Fixtures	1,445,000	68,000		**1,513,000**	713,000	33,000		**746,000**	**767,000**
1915	Office Furniture and Equipment	44,000	5,000		**49,000**	20,000	5,000		**25,000**	**24,000**
1920	Computer Equipment - Hardware	98,000	35,000		**133,000**	67,000	83,000		**150,000**	**(17,000)**
1925	Computer Software	228,000	53,000		**281,000**	165,000			**165,000**	**116,000**
1930	Transportation Equipment	1,708,000	250,000		**1,958,000**	1,074,000	173,000		**1,247,000**	**711,000**
1935	Stores Equipment	29,000			**29,000**	23,000	3,000		**26,000**	**3,000**
1940	Tools, Shop and Garage Equipment	214,000	26,000		**240,000**	91,000	24,000		**115,000**	**125,000**
1960	Miscellaneous Equipment									
1980	System Supervisory Equipment	1,755,000			**1,755,000**	1,563,000	25,000		**1,588,000**	**167,000**
1985	Sentinel Lighting	16,000			**16,000**	11,000	2,000		**13,000**	**3,000**
1995	Contributions and Grants	(371,000)			**(371,000)**	(61,000)			**(61,000)**	**(310,000)**
TOTALS DETAILED GENERAL LEDGER		**33,457,000**	**1,946,000**		**35,403,000**	**17,570,000**	**1,431,000**		**19,001,000**	**16,402,000**
1985	Sentinel Lighting Non LDC	16,000			**16,000**	11,000	2,000		**13,000**	**3,000**
TOTALS DETAILED LDC		**33,441,000**	**1,946,000**		**35,387,000**	**17,559,000**	**1,429,000**		**18,988,000**	**16,399,000**

Table 2-13: Fixed Asset Continuity Schedule - As of December 31, 2010 - DETAIL

		2010 Cost				2010 Accumulated Depreciation				2010 NBV
Description		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	134,000			**134,000**					**134,000**
1806	Land Rights	45,000	8,000		**53,000**	31,000	2,000		**33,000**	**20,000**
1820	Distribution Station Equipment - Normally	3,807,000	109,000		**3,916,000**	2,090,000	93,000		**2,183,000**	**1,733,000**
1830	Poles, Towers and Fixtures									
1835	Overhead Conductors and Devices	13,094,000	1,019,000		**14,113,000**	5,800,000	536,000		**6,336,000**	**7,777,000**
1840	Underground Conduit	4,872,000	281,000		**5,153,000**	2,148,000	208,000		**2,356,000**	**2,797,000**
1850	Line Transformers	4,201,000	45,000		**4,246,000**	2,770,000	161,000		**2,931,000**	**1,315,000**
1855	Services	1,878,000	60,000		**1,938,000**	1,066,000	68,000		**1,134,000**	**804,000**
1860	Meters	1,633,000	5,000		**1,638,000**	1,082,000	61,000		**1,143,000**	**495,000**
1905	Land	136,000			**136,000**					**136,000**
1908	Buildings and Fixtures	1,513,000	12,000		**1,525,000**	746,000	34,000		**780,000**	**745,000**
1915	Office Furniture and Equipment	49,000	10,000		**59,000**	25,000	6,000		**31,000**	**28,000**
1920	Computer Equipment - Hardware	133,000	25,000		**158,000**	150,000	45,000		**195,000**	**(37,000)**
1925	Computer Software	281,000	32,000		**313,000**	165,000			**165,000**	**148,000**
1930	Transportation Equipment	1,958,000	82,000		**2,040,000**	1,247,000	187,000		**1,434,000**	**606,000**
1935	Stores Equipment	29,000			**29,000**	26,000	3,000		**29,000**	
1940	Tools, Shop and Garage Equipment	240,000	26,000		**266,000**	115,000	24,000		**139,000**	**127,000**
1960	Miscellaneous Equipment									
1980	System Supervisory Equipment	1,755,000			**1,755,000**	1,588,000	21,000		**1,609,000**	**146,000**
1985	Sentinel Lighting	16,000			**16,000**	13,000	1,000		**14,000**	**2,000**
1995	Contributions and Grants	(371,000)			**(371,000)**	(61,000)			**(61,000)**	**(310,000)**
TOTALS DETAILED GENERAL LEDGER		**35,403,000**	**1,714,000**		**37,117,000**	**19,001,000**	**1,450,000**		**20,451,000**	**16,666,000**
1985	Sentinel Lighting Non LDC	16,000			**16,000**	13,000	1,000		**14,000**	**2,000**
TOTALS DETAILED LDC		**35,387,000**	**1,714,000**		**37,101,000**	**18,988,000**	**1,449,000**		**20,437,000**	**16,664,000**

OPDC capital spending January 1, 2009 through June 30, 2009:

From January 1 through June 30, 2009, OPDC has spent $360,000 of its planned 2009 capital expenditure budget of $1,868,000. Upon first review and based upon these numbers, it may appear as though the proposed capital projects and spending for 2009 will not be achieved. However, this is not the case and OPDC actually expects to slightly exceed its 2009 capital budget amount, with spending projected at $1,946,000. The rationale behind this expectation is as follows:

- OPDC's capital spending is typically back-end loaded in the calendar year. This is because the first half of the year is heavily weighted to completion of scheduled maintenance activities, including OPDC's comprehensive forestry management and tree trimming efforts. Furthermore, the majority of staff safety training initiatives are typically carried out in the first quarter of each calendar year.
- In 2009, OPDC had a significant amount of third party and City driven project to complete in the first half of the year. As a result, the majority of capital project work has been scheduled in the latter part of the year.
- The largest single item in OPDC's 2009 capital budget was the purchase of a new single bucket, material handling truck for our line department. We expect to take delivery of this $250,000 vehicle in the fourth quarter of 2009

OPDC is moving forward with its planned capital expenditures and expects to achieve its capital expenditure targets by year end.

GROSS FIXED ASSETS – FROM 2006 EDR TO 2010 TEST WITH VARIANCES

Table 2-14 presents OPDC balances in property plant & equipment from 2006 OEB approved through to 2010 Test. The summary section of Table 2-14 highlights the major components of OPDC's system including substations, poles and wires, transformers, meters and other plant. A more detailed breakdown follows below the summary for each capital asset general ledger account OPDC utilizes.

Variances between years over the materiality threshold of $50,000 are highlighted in yellow. Exhibit2 Tab 2 Schedule 4 summarizes the drivers for the material changes in property plant and equipment. Exhibit 2 Tab 4 Schedule 1 highlights significant changes to gross assets from capital expenditures for the years 2004 Actual through to 2010 Test. Additions to plant are the main driver for the majority of the variances shown below with two exceptions.

The balances in 2006 OEB Approved EDR are the average of the 2003 and 2004 year end fixed asset balances**. Essentially the variance between 2006 year end and 2006 EDR represents two and a half years (on average) of capital spending**. As can be seen in the continuity schedule for 2008 in Table 2-11, OPDC removed over $5.7 million in fully depreciated grouped assets from the general ledger accounts during that year. An equal and offsetting adjustment has also been made to accumulated depreciation and consequently this adjustment had no impact on either rate base or revenue requirement.

Note that any differences between the schedule below and the year end balances in the continuity schedules are due to rounding.

Table 2-14: Gross Fixed Assets Schedule - From 2006 EDR To 2010 Test With Variances

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
Distribution station equipment	2,769,700	3,671,700	3,757,500	3,687,900	3,807,000	3,916,000	902,000	85,800	(69,600)	119,100	109,000
Poles and wires	15,054,300	16,920,000	17,793,500	16,768,600	17,966,000	19,266,000	1,865,700	873,500	(1,024,900)	1,197,400	1,300,000
Line transformers	3,989,800	4,067,900	4,077,000	4,145,900	4,201,000	4,246,000	78,100	9,100	68,900	55,100	45,000
Services and meters	3,847,200	4,178,500	4,215,000	3,442,700	3,511,000	3,576,000	331,300	36,500	(772,300)	68,300	65,000
Land, land rights and buildings	1,182,900	1,409,400	1,469,500	1,692,200	1,828,000	1,848,000	226,500	60,100	222,700	135,800	20,000
Other distribution assets	5,195,100	5,411,100	5,489,600	3,704,200	4,074,000	4,249,000	216,000	78,500	(1,785,400)	369,800	175,000
TOTAL SUMMARY- LDC	**32,039,000**	**35,658,600**	**36,802,100**	**33,441,500**	**35,387,000**	**37,101,000**	**3,619,600**	**1,143,500**	**(3,360,600)**	**1,945,500**	**1,714,000**

1805	Land	-	-	-	74,100	134,000	134,000	-	-	**74,100**	**59,900**	-
1806	Land Rights	18,700	25,400	30,900	37,300	45,000	53,000	6,700	5,500	6,400	7,700	8,000
1820	Distribution Station Equipment - Nor	2,769,700	3,671,700	3,757,500	3,687,900	3,807,000	3,916,000	**902,000**	**85,800**	**(69,600)**	**119,100**	**109,000**
1830	Poles, Towers and Fixtures	346,800	397,100	418,700	-	-	-	**50,300**	21,600	**(418,700)**	-	-
1835	Overhead Conductors and Devices	10,133,600	11,539,600	12,253,300	12,106,200	13,094,000	14,113,000	**1,406,000**	**713,700**	**(147,100)**	**987,800**	**1,019,000**
1840	Underground Conduit	4,573,900	4,983,300	5,121,500	4,662,400	4,872,000	5,153,000	**409,400**	**138,200**	**(459,100)**	**209,600**	**281,000**
1850	Line Transformers	3,989,800	4,067,900	4,077,000	4,145,900	4,201,000	4,246,000	**78,100**	9,100	**68,900**	**55,100**	45,000
1855	Services	1,934,600	2,169,800	2,198,200	1,819,300	1,878,000	1,938,000	**235,200**	28,400	**(378,900)**	**58,700**	**60,000**
1860	Meters	1,912,600	2,008,700	2,016,800	1,623,400	1,633,000	1,638,000	**96,100**	8,100	**(393,400)**	9,600	5,000
1905	Land	170,700	189,100	206,200	135,700	136,000	136,000	18,400	17,100	**(70,500)**	300	-
1908	Buildings and Fixtures	993,500	1,194,900	1,232,400	1,445,100	1,513,000	1,525,000	**201,400**	37,500	**212,700**	**67,900**	12,000
1915	Office Furniture and Equipment	375,300	396,600	399,800	43,700	49,000	59,000	21,300	3,200	**(356,100)**	5,300	10,000
1920	Computer Equipment - Hardware	503,700	583,100	595,700	97,900	133,000	158,000	**79,400**	12,600	**(497,800)**	35,100	25,000
1925	Computer Software	404,500	607,700	622,200	228,300	281,000	313,000	**203,200**	14,500	**(393,900)**	**52,700**	32,000
1930	Transportation Equipment	1,513,800	1,688,900	1,699,800	1,707,700	1,958,000	2,040,000	**175,100**	10,900	7,900	**250,300**	**82,000**
1935	Stores Equipment	35,600	35,600	35,600	29,000	29,000	29,000	-	-	(6,600)	-	-
1940	Tools, Shop and Garage Equipment	487,800	545,400	582,700	214,400	240,000	266,000	**57,600**	37,300	**(368,300)**	25,600	26,000
1980	System Supervisory Equipment	1,925,200	1,925,200	1,925,200	1,754,600	1,755,000	1,755,000	-	-	**(170,600)**	400	-
1985	Sentinel Lighting	128,500	131,400	125,200	16,200	16,000	16,000	2,900	(6,200)	**(109,000)**	(200)	-
1995	Contributions and Grants	(105,700)	(371,400)	(371,400)	(371,400)	(371,000)	(371,000)	**(265,700)**	-	-	400	-
1565	CDM assets	54,900	-	-	-	-	-	**(54,900)**	-	-	-	-
TOTAL DETAILED GL - ALL		**32,167,500**	**35,790,000**	**36,927,300**	**33,457,700**	**35,403,000**	**37,117,000**	**3,622,500**	**1,137,300**	**(3,469,600)**	**1,945,300**	**1,714,000**
1985	Sentinel Lighting Non LDC	128,500	131,400	125,200	16,200	16,000	16,000	2,900	(6,200)	(109,000)	(200)	
TOTAL DETAILED GL - LDC		**32,039,000**	**35,658,600**	**36,802,100**	**33,441,500**	**35,387,000**	**37,101,000**	**3,619,600**	**1,143,500**	**(3,360,600)**	**1,945,500**	**1,714,000**

ACCUMULATED DEPRECIATION – FROM 2006 EDR TO 2010 TEST WITH VARIANCES

Table 2-15 presents OPDC balances in property plant & equipment – accumulated depreciation from 2006 OEB approved through to 2010 Test. Variances between years over the materiality threshold of $50,000 are highlighted in yellow.

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 OPDC's 2004 year end account balances, plus Tier 1 capital adjustments approved in OPDC'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.

A review of the continuity schedules in Exhibit 2, Tab 1 Schedule 3 in conjunction with the Table 2-15 shows that from 2006 Actual to the 2010 Test Year change in accumulated depreciation has been caused by annual deprecation expense and a significant adjustment in 2008. In 2008, OPDC removed over $5.7 million in fully depreciated grouped assets from its general ledger accounts. An equal and offsetting adjustment has also been made to gross assets. Other than the removal of fully amortized grouped assets, the change in accumulated depreciation is a result of new capital expenditures over a four year period and the amortization of assets that existed prior to that date. A detailed analysis of capital expenditures has been provided in Exhibit 2 Tab 4 Schedule 1.

Table 2-15: Property Plant & Equipment - Accumulated Amortization - From 2006 EDR To 2010 Test With Variances

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
Distribution station equipment	1,744,317	1,933,500	2,025,800	1,994,700	2,090,000	2,183,000	189,183	92,300	(31,100)	95,300	93,000
Poles and wires	6,477,148	7,961,100	8,647,200	7,254,700	7,948,000	8,692,000	1,483,952	686,100	(1,392,500)	693,300	744,000
Line transformers	1,893,526	2,288,700	2,447,500	2,609,100	2,770,000	2,931,000	395,174	158,800	161,600	160,900	161,000
Services and meters	2,213,213	2,569,800	2,709,800	2,018,100	2,148,000	2,277,000	356,587	140,000	(691,700)	129,900	129,000
Land, land rights and buildings	543,512	646,600	692,300	740,100	777,000	813,000	103,088	45,700	47,800	36,900	36,000
Other distribution assets	4,574,138	5,066,300	5,241,400	2,942,600	3,255,000	3,541,000	492,162	175,100	(2,298,800)	312,400	286,000
TOTAL SUMMARY- LDC	**17,445,854**	**20,466,000**	**21,764,000**	**17,559,300**	**18,988,000**	**20,437,000**	**3,020,146**	**1,298,000**	**(4,204,700)**	**1,428,700**	**1,449,000**

1806	Land Rights	18,168	21,300	23,700	27,400	31,000	33,000	3,132	2,400	3,700	3,600	2,000
1820	Distribution Station Equipment - No	1,744,317	1,933,500	2,025,800	1,994,700	2,090,000	2,183,000	**189,183**	**92,300**	(31,100)	**95,300**	**93,000**
1835	Overhead Conductors and Devices	4,683,493	5,739,900	6,216,400	5,303,900	5,800,000	6,336,000	**1,056,407**	**476,500**	**(912,500)**	**496,100**	**536,000**
1840	Underground Conduit	1,793,655	2,221,200	2,430,800	1,950,800	2,148,000	2,356,000	**427,545**	**209,600**	**(480,000)**	**197,200**	**208,000**
1850	Line Transformers	1,893,526	2,288,700	2,447,500	2,609,100	2,770,000	2,931,000	**395,174**	**158,800**	**161,600**	**160,900**	**161,000**
1855	Services	1,047,782	1,250,800	1,331,200	997,500	1,066,000	1,134,000	**203,018**	**80,400**	**(333,700)**	**68,500**	**68,000**
1860	Meters	1,165,431	1,319,000	1,378,600	1,020,600	1,082,000	1,143,000	**153,569**	**59,600**	**(358,000)**	**61,400**	**61,000**
1908	Buildings and Fixtures	525,344	625,300	668,600	712,700	746,000	780,000	**99,956**	43,300	44,100	33,300	34,000
1915	Office Furniture and Equipment	284,833	344,100	361,400	20,200	25,000	31,000	**59,267**	17,300	**(341,200)**	4,800	6,000
1920	Computer Equipment - Hardware	477,915	530,700	551,500	66,900	150,000	195,000	**52,785**	20,800	**(484,600)**	**83,100**	45,000
1925	Computer Software	401,784	480,100	524,300	165,500	165,000	165,000	**78,316**	44,200	**(358,800)**	(500)	-
1930	Transportation Equipment	1,260,773	1,393,300	1,446,100	1,074,500	1,247,000	1,434,000	**132,527**	**52,800**	**(371,600)**	**172,500**	**187,000**
1935	Stores Equipment	16,720	24,000	26,900	23,200	26,000	29,000	7,280	2,900	(3,700)	2,800	3,000
1940	Tools, Shop and Garage Equipment	350,983	433,100	467,200	90,600	115,000	139,000	**82,117**	34,100	**(376,600)**	24,400	24,000
1980	System Supervisory Equipment	1,785,363	1,892,800	1,907,500	1,563,200	1,588,000	1,609,000	**107,437**	14,700	**(344,300)**	24,800	21,000
1985	Sentinel Lighting	107,101	116,300	118,400	11,200	13,000	14,000	9,199	2,100	**(107,200)**	1,800	1,000
1995	Contributions and Grants	(4,233)	(31,800)	(43,500)	(61,500)	(61,000)	(61,000)	(27,567)	(11,700)	(18,000)	500	-
TOTAL DETAILED GL - ALL		**17,552,955**	**20,582,300**	**21,882,400**	**17,570,500**	**19,001,000**	**20,451,000**	**3,029,345**	**1,300,100**	**(4,311,900)**	**1,430,500**	**1,450,000**
1985	Sentinel Lighting Non LDC	107,101	116,300	118,400	11,200	13,000	14,000	9,199	2,100	**(107,200)**	1,800	1,000
TOTAL DETAILED GL - LDC		**17,445,854**	**20,466,000**	**21,764,000**	**17,559,300**	**18,988,000**	**20,437,000**	**3,020,146**	**1,298,000**	**(4,204,700)**	**1,428,700**	**1,449,000**

VARIANCE ANALYSIS EXPLANATIONS - GROSS FIXED ASSETS

The Gross Fixed Asset Variance analysis for variances identified as material (over $50,000) are highlighted in Table 2-14 of Exhibit 2, Tab 2, Schedule 2. Explanations and or reconciliations for those variances are provided in this schedule. Excerpts from the tables are shown before the explanation or reconciliation for each general ledger account. Amounts highlighted in yellow are explained.

The reconciliations will refer to OPDC capital expenditure analysis contained in Exhibit 2 Tab 4 Schedule 1. It is in that section where individual capital expenditures are explained. It should be noted that 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 variance amount for 2006 Actual from 2006 Board approved includes the difference between the 2004 actual and the 2006 Board Approved amounts as well as 2005 and 2006 expenditures. This explanation for the variance between 2006 OEB approved balance and the 2006 yearend balance applies to all of the accounts listed below and can be seen in the reconciliations for each material variance.

Note that any minor differences between capital expenditures in the reconciliations and the capital expenditures in Tab 4 Schedule 1 are due to rounding.

Explanation of Variance _ Land:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1805	Land	-	-	-	74,100	134,000	134,000
1905	Land	170,700	189,100	206,200	135,700	136,000	136,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
1805	Land	-	-	**74,100**	**59,900**	-
1905	Land	18,400	17,100	**(70,500)**	300	-

As a result of a review of general ledger accounts in 2008, OPDC reallocated the cost of land related to its substations to general ledger account 1805 out of 1905.

Explanation of Variance _ Distribution Station Equipment (Below 50kv):

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1820	Distribution Station Equipme	2,769,700	3,671,700	3,757,500	3,687,900	3,807,000	3,916,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1820	Distribution Station Equipment - Normally Pri		**902,000**	**85,800**	**(69,600)**	**119,100**	**109,000**

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**2,769,700**
Difference between average of 2003 & 2004 above and 2004 year end balance	**193,200**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**218,800**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**490,000**
2006 Year End account balance	**3,671,700**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**85,800**
2007 Year End account balance	**3,757,500**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**52,200**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(121,800)**
2008 Year End account balance	**3,687,900**
2009 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**119,100**
2009 Year End account balance	**3,807,000**
2010 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**109,000**
2010 Year End account balance	**3,916,000**

Explanation of Variance _ Overhead Distribution Lines & Feeders:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1830	Poles, Towers and Fixtures	346,800	397,100	418,700	-	-	-
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1830	Poles, Towers and Fixtures		**50,300**	21,600	**(418,700)**	-	-

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1835	Overhead Conductors and D	10,133,600	11,539,600	12,253,300	12,106,200	13,094,000	14,113,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1835	Overhead Conductors and Devices		**1,406,000**	**713,700**	**(147,100)**	**987,800**	**1,019,000**

Poles, fixtures and overhead conductors and devices are all grouped in general ledger account 1835 for ease of recording transactions in the field. For purposes of this variance analysis reconciliation below, OPDC has combined expenditures for both 1830 and 1835.

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**10,480,400**
Difference between average of 2003 & 2004 above and 2004 year end balance	**440,600**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**586,900**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**502,300**
2006 disposed assets removed from general ledger	**(73,500)**
2006 Year End account balance	**11,936,700**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**735,300**
2007 Year End account balance	**12,672,000**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**835,200**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(1,401,000)**
2008 Year End account balance	**12,106,200**
2009 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**987,800**
2009 Year End account balance	**13,094,000**
2010 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**1,019,000**
2010 Year End account balance	**14,113,000**

Explanation of Variance _ Underground Distribution Lines & Feeders:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1840	Underground Conduit	4,573,900	4,983,300	5,121,500	4,662,400	4,872,000	5,153,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1840	Underground Conduit		**409,400**	**138,200**	**(459,100)**	**209,600**	**281,000**

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**4,573,900**
Difference between average of 2003 & 2004 above and 2004 year end balance	**57,400**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**38,400**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**313,600**
2006 Year End account balance	**4,983,300**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**138,200**
2007 Year End account balance	**5,121,500**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**215,000**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(674,100)**
2008 Year End account balance	**4,662,400**
2009 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**209,600**
2009 Year End account balance	**4,872,000**
2010 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**281,000**
2010 Year End account balance	**5,153,000**

Explanation of Variance _ Distribution Transformers:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1850	Line Transformers	3,989,800	4,067,900	4,077,000	4,145,900	4,201,000	4,246,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1850	Line Transformers		**78,100**	9,100	**68,900**	**55,100**	45,000

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**3,989,800**
Difference between average of 2003 & 2004 above and 2004 year end balance	**38,000**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**33,100**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**7,000**
2006 Year End account balance	**4,067,900**

The 2008 and 2009 variances are the result of capital expenditure additions in those years.

Explanation of Variance _ Distribution Services:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1855	Services	1,934,600	2,169,800	2,198,200	1,819,300	1,878,000	1,938,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1855	Services		**235,200**	28,400	**(378,900)**	**58,700**	**60,000**

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**1,934,600**
Difference between average of 2003 & 2004 above and 2004 year end balance	**102,600**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**26,000**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**106,600**
2006 Year End account balance	**2,169,800**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**28,400**
2007 Year End account balance	**2,198,200**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**31,600**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(410,500)**
2008 Year End account balance	**1,819,300**
2009 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**58,700**
2009 Year End account balance	**1,878,000**
2010 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**60,000**
2010 Year End account balance	**1,938,000**

Explanation of Variance _ Meters:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1860	Meters	1,912,600	2,008,700	2,016,800	1,623,400	1,633,000	1,638,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1860	Meters		**96,100**	8,100	**(393,400)**	9,600	5,000

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**1,912,600**
Difference between average of 2003 & 2004 above and 2004 year end balance	**24,900**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**27,100**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**44,100**
2006 Year End account balance	**2,008,700**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**8,100**
2007 Year End account balance	**2,016,800**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**25,300**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(418,700)**
2008 Year End account balance	**1,623,400**

Explanation of Variance _ Buildings & Fixtures:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1908	Buildings and Fixtures	993,500	1,194,900	1,232,400	1,445,100	1,513,000	1,525,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1908	Buildings and Fixtures		**201,400**	37,500	**212,700**	**67,900**	12,000

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**993,500**
Difference between average of 2003 & 2004 above and 2004 year end balance	**4,100**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**156,900**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**40,400**
2006 Year End account balance	**1,194,900**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**37,500**
2007 Year End account balance	**1,232,400**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**226,900**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(14,200)**
2008 Year End account balance	**1,445,100**
2009 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**67,900**
2009 Year End account balance	**1,513,000**

Explanation of Variance _ Office Furniture & Equipment:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1915	Office Furniture and Equipme	375,300	396,600	399,800	43,700	49,000	59,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1915	Office Furniture and Equipment		21,300	3,200	**(356,100)**	5,300	10,000

2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**1,600**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(357,700)**
2008 Variance	**(356,100)**

Explanation of Variance _ Computer Equipment Hardware:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1920	Computer Equipment - Hardw	503,700	583,100	595,700	97,900	133,000	158,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1920	Computer Equipment - Hardware		**79,400**	12,600	**(497,800)**	35,100	25,000

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**503,700**
Difference between average of 2003 & 2004 above and 2004 year end balance	**900**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**66,700**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**11,800**
2006 Year End account balance	**583,100**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**12,600**
2007 Year End account balance	**595,700**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**6,800**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(504,600)**
2008 Year End account balance	**97,900**

Explanation of Variance _ Computer Equipment Software:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1925	Computer Software	404,500	607,700	622,200	228,300	281,000	313,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1925	Computer Software		**203,200**	14,500	**(393,900)**	**52,700**	32,000

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**404,500**
Difference between average of 2003 & 2004 above and 2004 year end balance	
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**178,000**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**25,200**
2006 Year End account balance	**607,700**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**14,500**
2007 Year End account balance	**622,200**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**10,600**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(404,500)**
2008 Year End account balance	**228,300**
2009 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**52,700**
2009 Year End account balance	**281,000**

Explanation of Variance _ Rolling Stock & Equipment:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1930	Transportation Equipment	1,513,800	1,688,900	1,699,800	1,707,700	1,958,000	2,040,000
Variance			[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
1930	Transportation Equipment		**175,100**	10,900	7,900	**250,300**	**82,000**

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**1,513,800**
Difference between average of 2003 & 2004 above and 2004 year end balance	**94,200**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**29,900**
2005 Disposals	**(16,300)**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**130,000**
2006 Disposals	**(62,700)**
2006 Year End account balance	**1,688,900**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**31,000**
2007 Disposals	**(20,100)**
2007 Year End account balance	**1,699,800**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**520,900**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(513,000)**
2008 Year End account balance	**1,707,700**
2009 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**250,300**
2009 Year End account balance	**1,958,000**
2010 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**82,000**
2010 Year End account balance	**2,040,000**

Explanation of Variance _ Major Tools:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1940	Tools, Shop and Garage Equ	487,800	545,400	582,700	214,400	240,000	266,000
Variance			[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
1940	Tools, Shop and Garage Equipment		**57,600**	37,300	**(368,300)**	25,600	26,000

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**487,800**
Difference between average of 2003 & 2004 above and 2004 year end balance	**12,600**
2005 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**20,500**
2006 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**24,500**
2006 Year End account balance	**545,400**
2007 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**37,300**
2007 Year End account balance	**582,700**
2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1 summary only	**38,900**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(407,200)**
2008 Year End account balance	**214,400**

Explanation of Variance _ SCADA:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1980	System Supervisory Equipme	1,925,200	1,925,200	1,925,200	1,754,600	1,755,000	1,755,000
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1980	System Supervisory Equipment		-	-	**(170,600)**	400	-

2008 Capital expenditures as per Exhibit 2 Tab 4 Schedule 1	**207,700**
2008 adjustment to remove fully amortized assets from gross assets and accumulated depreciation	**(378,300)**
2008 Variance	**(170,600)**

Explanation of Variance _ Contributions & Grants:

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
1995	Contributions and Grants	(105,700)	(371,400)	(371,400)	(371,400)	(371,000)	(371,000)
Variance			**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**
1995	Contributions and Grants		**(265,700)**	-	-	400	-

2006 OEB Approved Balance (average of 2003 & 2004 year end balances)	**(105,700)**
Difference between average of 2003 & 2004 above and 2004 year end balance	**(105,700)**
Reallocation to contributed capital - underground	**(81,300)**
Reallocation to contributed capital - services	**(55,700)**
Reallocation to contributed capital - transformation	**(23,000)**
2006 Year End account balance	**(371,400)**

OM&A EXP. INCLUDED IN WORKING CAPITAL ALLOWANCE CALCULATION

Summary totals of the expenses included in OPDC's working capital allowance calculation were presented in Table 2-2 earlier in this exhibit (Tab 1 Schedule 1). OPDC has forecast its working capital allowance to be $4,211,700 for 2010 and has based it on the "15% of specific OM&A accounts formula approach" referred to in the Board's Filing Requirements (section 2.3.4).

OPDC has provided a summary of all accounts (operations and maintenance and administration) included in the working capital calculation shown earlier in Table 2-2 for each of 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year in Table 2-16. OPDC has multiplied the 2010 Test year expenses by 15% to determine its allowable working capital for purposes of determining its rate base.

OPDC has provided a spreadsheet setting out OPDC's Cost of Power calculations in Table 2-17 to this Schedule.

Table 2-16: Accounts Included In Working Capital Allowance Calculation - Operations & maintenance

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
DISTRIBUTION EXPENSES - OPERATIONS					
5005-Operation Supervision and Engineering	378,500	440,000	500,200	518,000	645,000
5010-Load Dispatching	213,200	232,700	217,200	249,000	261,000
5016-Distribution Station Equipment - Operation Labour	21,400	25,800	21,400	27,000	27,000
5017-Distribution Station Equipment - Operation Supplies and I	167,800	98,600	198,600	160,000	147,000
5020-Overhead Distribution Lines and Feeders - Operation Lab	6,700	10,600	13,100	12,000	13,000
5025-Overhead Distribution Lines and Feeders - Operation Sup	28,300	30,800	26,500	36,000	38,000
5030-Overhead Subtransmission Feeders - Operation	77,900	57,600	32,100	-	-
5070-Customer Premises - Operation Labour	10,700	5,700	2,700	2,000	2,000
Distribution Expenses - Operation Total	**904,500**	**901,800**	**1,011,800**	**1,004,000**	**1,133,000**
DISTRIBUTION EXPENSES - MAINTENANCE					
5120-Maintenance of Poles, Towers and Fixtures	295,300	501,800	427,400	371,000	396,000
5125-Maintenance of Overhead Conductors and Devices	48,700	49,500	49,200	83,000	102,000
5145-Maintenance of Underground Conduit	112,400	77,100	112,700	109,000	98,000
5160-Maintenance of Line Transformers	44,300	57,100	59,100	70,000	56,000
5170-Sentinel Lights - Labour	5,200	4,800	4,900	4,000	4,000
5172-Sentinel Lights - Materials and Expenses	2,600	4,500	4,100	4,000	4,000
5175-Maintenance of Meters	49,700	33,100	32,800	58,000	38,000
5186-Water heater maintenance	61,200	-	-	-	-
Distribution Exp - Maintenance Total	**619,400**	**727,900**	**690,200**	**699,000**	**698,000**
Less Non-LDC Expenses 5170, 5172, 5186	69,000	9,300	9,000	8,000	8,000
Distribution Exp - Maintenance LDC	**550,400**	**718,600**	**681,200**	**691,000**	**690,000**
Distribution Exp - O&M - Total	**1,454,900**	**1,620,400**	**1,693,000**	**1,695,000**	**1,823,000**

Table 2-16: Accounts Included In Working Capital Allowance Calc. (Continued) - Billing & Collections, Community Relations

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
BILLING AND COLLECTIONS					
5310-Meter Reading Expense	136,600	123,000	132,400	140,000	145,000
5315-Customer Billing	730,300	662,900	627,800	640,000	664,000
5320-Collecting	73,600	55,000	52,600	50,000	50,000
5330-Collection Charges	11,500	21,200	17,800	21,000	22,000
5335-Bad Debt Expense	(60,100)	72,700	85,400	235,000	160,000
Billing and Collecting Total	**891,900**	**934,800**	**916,000**	**1,086,000**	**1,041,000**
COMMUNITY RELATIONS					
5410-Community Relations - Sundry	7,900	9,200	10,900	24,000	21,000
5415-Energy Conservation	19,500	28,300	500	-	-
Community Relations Total	**27,400**	**37,500**	**11,400**	**24,000**	**21,000**
Billing & Collections, Community relations Total	**919,300**	**972,300**	**927,400**	**1,110,000**	**1,062,000**

Table 2-16: Accounts Included In Working Capital Allowance Calculation (Continued) - Administration & General

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
ADMINISTRATION AND GENERAL					
5605-Executive Salaries and Expenses	277,700	291,200	302,500	308,000	319,000
5610-Management Salaries and Expenses	298,000	347,900	372,700	390,000	403,000
5615-General Administrative Salaries and Expenses	172,200	170,000	174,100	178,000	185,000
5620-Office Supplies and Expenses	185,300	172,100	157,200	195,000	210,000
5625-Administrative Expense Transferred-Credit	(331,900)	(318,400)	(325,100)	(316,000)	(330,000)
5630-Outside Services Employed	101,600	93,800	89,300	143,000	125,000
5635-Property Insurance	21,700	20,700	20,900	23,000	24,000
5640-Injuries and Damages	26,400	24,300	25,200	27,000	28,000
5655-Regulatory Expenses	45,300	55,200	48,900	52,000	87,000
5660-General Advertising Expenses	24,700	27,600	27,300	30,000	30,000
5665-Miscellaneous Expenses	27,500	34,500	59,600	70,000	71,000
5675-Maintenance of General Plant	228,200	233,000	235,600	238,000	245,000
Administrative and General Expenses Total	**1,076,700**	**1,151,900**	**1,188,200**	**1,338,000**	**1,397,000**
TAXES OTHER THAN INCOME TAXES					
6105-Taxes Other Than Income Taxes	23,700	24,200	24,900	27,000	27,000
6105-Taxes Other Than Income Taxes - Cap Tax	42,200	43,900	10,600	19,000	6,000
Taxes Other Than Income Taxes Ex CT	**65,900**	**68,100**	**35,500**	**46,000**	**33,000**
OTHER DEDUCTIONS					
6035-Other Interest Expense	84,100	44,700	37,400	10,000	25,000
6205-Donations	13,400	25,600	20,500	20,000	20,000
Other Items Total	**97,500**	**70,300**	**57,900**	**30,000**	**45,000**
Donations not related to customers	7,000	7,800	13,500	14,000	14,000
Other Total - excluding discretionary donations	**90,500**	**62,500**	**44,400**	**16,000**	**31,000**
Total Administration & General	**1,233,100**	**1,282,500**	**1,268,100**	**1,400,000**	**1,461,000**

CALCULATION OF COST OF POWER FOR WORKING CAPITAL ALLOWANCE

Table 2-17 summarizes OPDC's calculation of cost of power for purposes of determining the working capital allowance in Table 2-2. For comparison purposes, 2006 Actual through to 2010 Test has been presented.

The summary below shows the actual balances recorded in the general ledger at year end for 2006 through 2008 (top half) as well as the amounts paid (rates multiplied by billing determinants - bottom). The amounts for each category are different due to year end adjusting entries recording settlement variances to equalize sale of power and cost of power. For purposes of determining working capital allowance **no settlement variances are assumed for 2009 & 2010.**

Prior to Bill 35, certain arrangements for the wheeling of all power generated by two of our waterpower plants existed to the benefit of our customers between the former Orillia Water Light and Power Commission and Ontario Hydro. OPDC worked to ensure that these wheeling arrangements were preserved by provincial statute when Bill 35 was enacted. As a result, Orillia Power Distribution CUSTOMERS continue to benefit, post Bill 35, in the form of lower overall power costs due to the receipt of various credits to both wholesale market service and transmission costs.

Table 2-17: Cost of Power Accounts Included In Working Capital Allowance Calculation

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
SUMMARY PER YEAR END GENERAL LEDGER INCLUDING RETAIL SETTLEMENT VARIANCE ADJUSTMENTS AT YEAR END					
4705-Power Purchased	17,685,500	18,696,400	18,333,700	19,583,000	20,044,000
4708-WMS	2,054,500	2,064,800	2,051,100	1,333,000	1,459,000
4714-NW	1,471,400	1,305,400	1,137,000	989,000	1,055,000
4716-NCN	1,262,600	1,103,500	1,047,500	927,000	989,000
4750-LV Charges	141,100	221,100	221,700	210,000	185,000
TOTAL COST OF POWER	**22,615,100**	**23,391,200**	**22,791,000**	**23,042,000**	**23,732,000**
SUMMARY OF COST OF POWER (RATES MULTIPLIED BY BILLING DETERMINANTS)					
Cost of power	$18,798,300	$18,883,300	$18,845,000	$19,579,000	$20,040,000
WMSC and RRP	$1,151,900	$1,297,300	$1,280,900	$1,333,000	$1,459,000
Transmission costs	$2,343,300	$2,520,900	$2,017,900	$1,916,000	$2,044,000
Low voltage charges	$259,800	$422,500	$407,400	$210,000	$185,000
Long term load transfers	$73,100	$9,900	$4,100	$4,000	$4,000
Settlement variance adjustments	-$11,300	$257,300	$235,700		
TOTAL COST OF POWER	**$22,615,100**	**$23,391,200**	**$22,791,000**	**$23,042,000**	**$23,732,000**

Table 2-17 (continued): Cost of Power Accounts Included In Working Capital Allowance Calculation

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
POWER PURCHASED __ FROM IESO					
kWh purchased from IESO	320,647,650	325,180,970	316,385,030	314,040,422	330,047,301
Price per kWh includes global adjustment	$0.0558	$0.0557	$0.0562	$0.0607	$0.0607
Cost of power	**$17,877,500**	**$18,125,100**	**$17,793,200**	**$19,069,000**	**$20,040,000**
POWER PURCHASED __ FROM OPGC					
kWh purchased from OPGC	19,189,012	15,169,945	20,957,182	17,000,000	-
Price per kWh excludes global adjustment	$0.0480	$0.0500	$0.0502	$0.0300	
Cost of power	**$920,800**	**$758,200**	**$1,051,800**	**$510,000**	
POWER PURCHASED __ COMBINED					
kWh purchased COMBINED	339,836,662	340,350,915	337,342,212	331,040,422	330,047,301
Spot price per kWh	$0.0553	$0.0555	$0.0559	$0.0591	$0.0607
Cost of power	**$18,798,300**	**$18,883,300**	**$18,845,000**	**$19,579,000**	**$20,040,000**

Table 2-17 (continued): Cost of Power Accounts Included In Working Capital Allowance Calculation

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
WMSC and RRP					
kWh purchased from IESO	320,647,650	325,180,970	316,385,030	314,040,422	330,047,301
Spot price per kWh	$0.0050	$0.0050	$0.0056	$0.0056	$0.0056
WMSC and RRP	**$1,599,900**	**$1,619,700**	**$1,783,900**	**$1,755,000**	**$1,852,000**
WSMC CREDIT RECEIVED FROM HYDRO ONE					
kWh generation production for credit	72,266,000	51,999,000	81,132,000	68,000,000	63,400,000
Spot price per kWh	-$0.0062	-$0.0062	-$0.0062	-$0.0062	-$0.0062
Credit received	**-$448,000**	**-$322,400**	**-$503,000**	**-$422,000**	**-$393,000**
WHOLESALE MARKET SERVICE CHARGES AND RURAL RATE PROTECTION					
WMSC and RRP	$1,599,900	$1,619,700	$1,783,900	$1,755,000	$1,852,000
Credit received	-$448,000	-$322,400	-$503,000	-$422,000	-$393,000
WMSC and RRP Net of Credit	**$1,151,900**	**$1,297,300**	**$1,280,900**	**$1,333,000**	**$1,459,000**

Table 2-17 (continued): Cost of Power Accounts Included In Working Capital Allowance Calculation

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
TRANSMISSION RATES					
Network	$2.5200	$2.5200	$2.0100	$2.0100	$2.0100
Line or Connection	$2.0900	$2.0900	$1.8800	$1.8800	$1.8800
Combined rate	$4.6100	$4.6100	$3.8900	$3.8900	$3.8900
DEMAND					
Network	603,827	634,518	590,678	584,000	614000
Line or Connection	603,827	634,518	590,678	584,000	614000
DEMAND REDUCTION CREDITS FOR PRESERVED WHEELING ARRANGMENTS					
Network	(98,858)	(75,277)	(100,925)	(92,000)	(89,000)
Line or Connection	(98,299)	(74,340)	(99,446)	(91,000)	(88,000)
TRANSMISSION COSTS NET OF WHEELING					
Network	$1,272,500	$1,409,300	$1,068,000	$989,000	$1,055,000
Line or Connection	$1,056,600	$1,170,800	$958,000	$927,000	$989,000
Other adjustments	$14,200	-$59,200	-$8,100		
Net Transmission costs	**$2,343,300**	**$2,520,900**	**$2,017,900**	**$1,916,000**	**$2,044,000**

CAPITAL EXPENDITURES

OPDC has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending and asset management.

As required by the filing guidelines, capital expenditures presented are from 2004 Actual through 2010 Test. The expenditures are summarized first by general ledger account then by work order within each general ledger account. A description and rationale for each of the projects exceeding the materiality threshold of $50,000 is included below the spreadsheet analysis for each major function (i.e. overhead, underground etc.).

The OPDC Board-approved capital and operations budget was presented in Appendix 1-J of Exhibit 1. The first two pages below provide a more detailed summary of the capital budget by asset category. Detail for each major asset category explained as part of the variance analysis follow below the summaries.

Capital Expenditure Analysis _ Summary:

DISTRIBUTION CORPORATION CAPITAL EXPENDITURES SUMMARY		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
CAPITAL EXPENDITURES SUMMARY FOR DISTRIBUTION CORPORATION								
Land & Buildings								
Land - Distibution Plant	**1805-00**	3,800	16,500		17,100	3,600	60,000	
Land Rights	**1806-00**		6,200	500	5,500	6,300	8,000	**8,000**
Buildings & Fixtures - Service Centre	**1908-00**	8,100	157,000	40,400	37,500	226,900	68,000	**12,000**
		11,900	179,700	40,900	60,100	236,800	136,000	**20,000**
Substations / Subtransmission / Distribution System								
Overhead Conductors & Devices	**1835-00**	881,300	586,900	502,300	735,300	835,200	988,000	**1,019,000**
Substations	**1820-00**	386,400	218,800	490,000	85,800	52,200	119,000	**109,000**
Services	**1855-00**	205,200	26,000	106,600	28,400	31,700	59,000	**60,000**
Underground	**1840-00**	115,000	38,400	313,600	138,100	215,100	210,000	**281,000**
Transformers	**1850-00**	75,800	33,100	7,100	9,100	68,900	55,000	**45,000**
Meters	**1860-00**	49,800	27,000	44,100	8,100	25,300	10,000	**5,000**
		1,713,500	930,200	1,463,700	1,004,800	1,228,400	1,441,000	**1,519,000**
Subtotal		**1,725,400**	**1,109,900**	**1,504,600**	**1,064,900**	**1,465,200**	**1,577,000**	**1,539,000**

Capital Expenditure Analysis _ Summary (continued):

DISTRIBUTION CORPORATION CAPITAL EXPENDITURES SUMMARY		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
Other Capital Assets								
Office Furniture & Equipment	**1915-00**	2,100	3,000	17,000	3,200	1,600	5,000	**10,000**
Computer Equipment - Hardware	**1920-00**	1,800	66,700	11,700	12,600	6,800	35,000	**25,000**
Computer Software	**1925-00**		178,100	25,100	14,500	10,600	53,000	**32,000**
Transortation Equipment (Vehicles)	**1930-00**	278,000	29,900	129,900	31,000	520,900	250,000	**82,000**
Major Tools and Equipment	**1940-00**	25,300	20,400	24,500	37,400	38,800	26,000	**26,000**
SCADA (System Supervisory Equipment)	**1980-00**					207,700		
Contributions & Grants	**1995-00**	(211,400)		(160,000)				
Sentinel Lighting	**1985-00**	1,300	3,400	(300)	1,700			
		97,100	**301,500**	**47,900**	**100,400**	**786,400**	**369,000**	**175,000**
TOTAL DISTRIBUTION CORP		**1,822,500**	**1,411,400**	**1,552,500**	**1,165,300**	**2,251,600**	**1,946,000**	**1,714,000**

Capital Expenditure Analysis _ Land:

LAND & BUILDINGS LAND __ GL # 1805 / 1806 / 1905		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
LAND __ GL # 1805 / 1806 / 1905								
Land rights / easements	**22-YR-0019**		6,200	500	5,500	6,300	8,000	**8,000**
New South substation - Jarvis St.	**22-05-1535**	3,800	16,500					
New substation - Tudhope Park @ Couchiching	**22-04-1536**						60,000	
New substation - Harvey Settlement Rd	**22-06-1558**				17,100	3,600		
		3,800	**22,700**	**500**	**22,600**	**9,900**	**68,000**	**8,000**

1. Tudhope Park @ Couchiching ($60,000 in 2009) - The projected $60,000 expenditure in 2009 relates to the purchase of land for substation development. Through the implementation of its Asset Management Plan, OPDC recognized the future requirement for a new substation, driven by expected load growth as the result of continued development within the community.

Capital Expenditure Analysis _ Buildings & Fixtures:

LAND & BUILDINGS BUILDINGS AND FIXTURES __ GL # 1908		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
SERVICE CENTRE __ GL # 1908								
Renovations to Control Room & Meter Room	**22-04-1521**	8,100	157,000					
Install gas heat in service centre	**22-06-1559**			3,900	33,200			
Power gate moved from old control	**22-06-1560**			27,800	500			
Concrete compound structure - sand	**22-06-1561**			5,600				
Transformer vault - confined space training	**22-06-1562**			3,100				
Storage Shed Addition	**22-07-1579**				3,800	151,400		
Office Re-config - engineering / control ctr.	**22-08-1592**					54,000		
Driveway Refurbishment	**22-08-1594**						13,000	
Todd's Shop - Demolition / Property Improvemer	**22-08-1593**					21,500		
Service Centre Roof Upgrade	**22-09-1624**						25,000	
Warehouse shelving replacement	**22-10-NEW**						30,000	
Sprinkler upgrades - warehouse	**22-10-NEW**							**12,000**
		8,100	**157,000**	**40,400**	**37,500**	**226,900**	**68,000**	**12,000**

1. Renovations to Control Room & Meter Room ($8,000 in 2004 plus $157,000 in 2005) – Prior to 2005, OPDC's control centre was housed in a building located several kilometres from the main administrative office / warehouse facility. In order to avoid significant costs to carry out necessary upgrades to the old control centre and to realize substantial efficiency gains, OPDC enacted a plan to relocate the control centre within the existing main office facility. To realize further savings, necessary improvements to OPDC's meter room were carried out as part of the same construction project. Preliminary design and job preparations were undertaken in 2004 with the main construction phase of the project completed in 2005.

2. Storage Shed Addition ($4,000 in 2007 plus $151,000 in 2008) – A storage shed was added to the side of the existing warehouse facility at 360 West Street in Orillia. This addition was undertaken to provide a space where wire reels, transformers and other utility inventory could be protected from the elements and stored is a more secure manner within the facility. Prior to this addition, these inventory items were stored within OPDC's yard and were exposed to the elements. Given the severe winter conditions often experienced in this service territory, significant staff time was often required to access items that were buried in snow. This in turn could have negative impacts on Service Quality Indicators. With this addition, efficiency has been greatly increased, as line personnel can quickly find and access the inventory items required to complete their work.

3. Office Re-configuration – Engineering / Control Centre / Meeting Room ($54,000 in 2008) – In 2008, OPDC increased staffing in engineering to, among other things, comply with increased regulatory reporting. To accommodate the additional staff, modifications to existing office space were required. To achieve maximum value, required improvements to the control room and office boardroom were grouped into the same construction project.

Capital Expenditure Analysis _ Substations:

SUBSTATIONS SUBSTATIONS __ GL # 1820		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
SUBSTATIONS __ GL # 1820								
Replace metering at M1, M7, M8 Feeders	**22-03-1517**	386,400		15,600				
New South Substation at Water Filtration Plant	**22-05-1537**		218,800	474,400	11,200			
Install oil retainers at Substations	**22-07-1581**						40,000	**40,000**
Central Substation - Terminate new switch	**22-07-1580**				21,000			
North Sub - Refurbishment / Feeder Cable Re-rc	**22-07-1589**				53,600			
James Street - Feeder Cable Upgrade	**22-08-1596**					46,100		
Progress Park - Feeder Cable Upgrade	**22-08-1597**							**27,000**
Battery Bank Replacement (Substations)	**22-09-1609**						54,000	
Meter upgrades & Reconfiguration (M4, M7, M8)	**22-10-NEW**							**15,000**
Central Sub retaining wall rebuild	**22-09-NEW**						25,000	
Feeder Cable 2 Re-routing - Couch Sub								**27,000**
Other capital expenditures						6,100		
		386,400	**218,800**	**490,000**	**85,800**	**52,200**	**119,000**	**109,000**

1. Replace metering at M1, M7 & M8 feeders ($386,000 in 2004) – This was a mandatory project that was part of Hydro One's Wholesale Meter Exit Program. It involved elimination of the metering points at the Orillia Transformer Station and re-establishment of the metering points on all three feeder lines at Orillia's boundary.

2. South Substation at Water Filtration Plant (a.k.a. Jarvis Substation) ($219,000 in 2005 plus $474,000 in 2006 plus $11,000 in 2007) – This project was started in 2005 with the newly completed substation put into service in 2006 and a few residual costs trailing into 2007. This project enabled OPDC to remove the original South Substation from service as it had reached its expected useful life. In addition, the new substation led to improved reliability and was strategically positioned to minimize system losses as well as to better support the 4 kV system and accommodate future growth in the core city area.

3. North Substation Refurbishment / Feeder Cable Re-Routing ($54,000 in 2007) – This project involved replacement of aging components on the substation structure to increase reliability and remove potential safety hazards with the old equipment. This project enhanced the service potential of the asset by extending its useful life.

4. Battery Bank Replacements ($54,000 in 2009) – Battery banks at three OPDC substations are scheduled for upgrade / replacement in 2009. This project will result in enhanced service potential of the assets through improved reliability and reduction in ongoing maintenance costs, in addition to providing improved safety for workers.

Capital Expenditure Analysis _ Distribution Overhead:

OVERHEAD CONDUCTORS AND DEVICES GL # 1835		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
OVERHEAD CONDUCTORS AND DEVICES_GL # 1835								
Pole replacement - subtransmission	**22-YR-0010**	12,600	8,400	1,000	43,000	800	23,000	
Matthias Tie into Hydro Grid on Hwy 169	**22-06-1565**			5,200	9,800	120,600	20,000	
Matthias Line (Teardown @ Kennedy Bridge - A	**22-08-1595**					1,100	85,000	
Sale of Matthias Line assets to OPGC							(128,000)	
Pole replacement 44 kV lines	**22-YR-0001**	183,200	64,000	119,000	156,100	114,400	45,000	**88,000**
Load Break Switches	**22-YR-0023**	4,800	40,400	5,600		12,100	117,000	**119,000**
East St Rebuild from James/Clayborne (44 kv)	**22-05-1538**			51,600				
North St Rebuild from West/Bay St. (44 kv)	**22-05-1539**		309,100	27,600				
Cowan St Rebuild - Borland to Jarvis (44 kv)	**22-04-1533**	2,400	47,200	65,900				
New O/H Line Old Barrie Road	**22-03-1513**	340,800	1,100					
4th Feeder Pole Line Extension - Uthoff Line	**22-03-1516**	185,700	200					
Pole Line Ext 15th Line	**22-03-1500**	100	(50,000)					
West St. - James to King	**22-06-1578**			1,100	354,200			
Reconstruct West St N - Borland to Brant	**22-08-1598**					92,600		
James St Rebuild - West St to High St	**22-08-1599**					179,700		
Terminal Station - Elec. Structure Teardown and	**22-08-1600**					153,800		

Continued on next page

Capital Expenditure Analysis _ Distribution Overhead (continued):

OVERHEAD CONDUCTORS AND DEVICES (cont'd) GL # 1835		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
Wireless communications to four 44kV meter po	**22-09-1610**						29,000	
Lakehead University - System upgrades	**22-09-NEW**						100,000	
Proximity Issues - Mississaga & Andrew 44kV	**22-09-NEW**						125,000	
Pole replacement (Overhead)	**22-YR-0002**	89,700	146,300	203,100	139,200	146,800	140,000	**211,000**
Patrick St Rebuild - Nottawasaga to Brant St.	**22-06-1563**			11,800			30,000	**198,000**
Coldwater Rd move pole line - City driven projec	**21-06-6747**							
Conductor upgrades & reconductoring	**22-YR-0021**	10,900	7,300	10,800	11,400	11,300	32,000	**17,000**
Install fault indicators	**22-YR-0028**	11,600	12,800					
Cowan St Rebuild - North St E to Borland	**22-05-1540**		100					
Rebuild pole line rear of Fred's Meat Market	**22-04-1518**	39,500						
Reconstruct rear of BDO Dunwoody	**22-07-1582**				21,600			**78,000**
Westmount Drive - Coldwater to Mississaga	**22-09-1611**						180,000	
Colbourne to Andrew Re-build	**22-09-1612**							**189,000**
Line 15 North - Pick up Load Transfer Cust's	**22-09-1613**						65,000	**119,000**
Proximity Issues - Mississaga & Andrew 4.16 kv	**22-09-NEW**						125,000	
Other capital expenditures				(400)		2,000		
		881,300	**586,900**	**502,300**	**735,300**	**835,200**	**988,000**	**1,019,000**

1. Matthias Line Tie into Hydro One Grid on Hwy 169 ($156,000 in 2006 through 2009) – Through 2009, power produced at the Matthias Generating Station was fed directly into the OPDC system through the Matthias sub-transmission line. It was determined in 2006 that tying this transmission line into the Hydro One grid where it meets Highway 169, would enable the company to avoid significant and costly future repairs and upgrades to a major section of this transmission line. In addition, this project would enable OPDC to remove its 44 kV switching structure from service as it is at the end of its useful life and presents a safety risk to staff. Preliminary design work, negotiations with Hydro One and job preparation were carried out in 2006 and 2007 with the majority of the work completed in 2008. The final connection is planned for 2009. Upon completion of the tie-in to Hydro One, the remaining, active section of the Matthias sub-transmission line will be sold to Orillia Power Generation Corporation (OPGC).

2. Matthias Line Teardown @ Kennedy Bridge – Atherley ($86,000 in 2009) – This project is closely related to the Matthias Line Tie In project described above. Once the tie in with Hydro One is complete, OPDC is obligated by ESA regulations to remove the de-energized / obsolete section of line within six months. These costs are considered Asset Retirement Obligations as defined in section 3110 of the CICA Handbook and must be capitalized and will be subsequently recovered upon the sale to OPGC.

3. Pole Replacement 44 kV lines ($183,000 in 2004, $64,000 in 2005, $119,000 in 2006, $156,000 in 2007, $114,000 in 2008, $45,000 in 2009 & $88,000 in 2010) – As part of OPDC's asset management plan, a comprehensive cycle of testing for all OPDC poles is utilized to test pole integrity, identify weaknesses and determine follow up test dates. Through this testing and other asset monitoring methodologies, poles that are determined to have reached the end of

their useful life or that have sustained damage, are scheduled for replacement each year. These annual costs are not project specific but represent change out of individual poles as required.

4. Load Break Switches ($117,000 in 2009 & $119,000 in 2010) – In 2009, OPDC began a multi-year program of systematically upgrading existing air brake switches with load brake switches. The new devices provide far greater control for system operation, improve reliability and employee safety. The costs in both 2009 and 2010 represent upgrading of four units per year. By upgrading these switches it will enable further efficiencies and reliability improvements in the future as OPDC plans to automate these switches to enable remote control. OPDC is planning to begin the 2010 installation in October, with completion scheduled for November.

5. East Street Re-build James / Clayborne ($52,000 in 2006) – This project included replacement of five poles and was driven by the age of the existing plant which had surpassed its useful life.

6. North Street Re-build from West / Bay Street ($337,000 completed in 2006) – The project was split into two phases with a start date in 2005 and phase two completion and an in service date of 2006. This project included replacement of thirty poles that had reached their expected useful life. In addition, this project enabled improved reliability and diversity within OPDC's system.

7. Cowan Street Re-build Borland to Jarvis ($115,000 – completed in 2006) - The project start date was in 2004 with an in service date of 2006. Although some preliminary design and planning was undertaken in 2004, the majority of the work was split into two phases that were completed in 2005 and 2006 respectively. The project involved installation and stringing of seven poles in preparation for the new 4 kV Jarvis substation and related feeders.

8. New O/H Line – Old Barrie Road ($341,000 in 2004) – This 34 poles project enabled OPDC to complete a full system loop around the service territory with its 44 kV and 13.8 kV feeders. This design resulted in excellent system diversity, improved reliability and enhanced OPDC's ability to service an annexed territory and expected future load growth.

9. 4th Feeder Pole Line Extension – Uthoff Line ($186,000 in 2004) – This 16 pole project extended OPDC's 44 kV system to the boundary of the service territory to connect to Hydro One's M4 circuit out of Orillia Transformer Station. This provided Orillia with a fourth feed in order to accommodate load growth and additional reliability.

10. Pole Line Extension – 15th Line ($50,000 credit in 2005) – In 2003, this project was completed and put in service with a total project cost of $307,000. Part of the total project cost was a year end accrual to capture anticipated costs from Hydro One for transferring conductor and devices to OPDC poles. These costs never materialized and the accrual was reversed by OPDC with adjustment made to reverse depreciation that had been expensed in 2003 and 2004.

11. West Street – James to King ($354,000 in 2006) – The scope of this project involved replacing 15 poles and conductor along West Street and was driven by the age of the existing plant which had surpassed their useful life.

12. Reconstruct West Street – Borland to Brant ($93,000 in 2008) – The scope of this project involved relocation of an existing 44 kV pole line in order to accommodate a city road widening.

13. James Street Re-build – West to High ($180,000 in 2008) – The scope of this project involved replacing 8 poles along James Street and was driven by the age of the existing plant which had surpassed their useful life.

14. Terminal Station – Electrical Structure Teardown and Re-vamp ($154,000 in 2008) – This project was a critical element in the overall goal of enabling OPDC to remove its 44 kV switching structure from service as it was at the end of its useful life and presented a safety risk to staff.

15. Lakehead University – System Upgrades ($100,000 in 2009) – Lakehead University is scheduled to open a new Orillia campus in 2011. In preparation for this significant development within the community, 44 kV system upgrades and new construction are required in 2009 to feed the new facility.

16. Proximity Issues – Mississaga & Andrew – 44kV ($125,000 in 2009) – The project scope was to replace existing construction that was not compliant with today's more stringent standards, in particular related to proximity conductor to buildings (ESA regulation 22/04 – Proximity to Structures).

17. Pole Replacement – Overhead ($90,000 in 2004, $146,000 in 2005, $203,000 in 2006, $139,000 in 2007, $147,000 in 2008, $140,000 in 2009 & $211,000 in 2010) – As part of OPDC's asset management plan, a comprehensive cycle of testing for all OPDC poles is utilized to test pole integrity, identify weaknesses and determine follow up test dates. Through this testing and other asset monitoring methodologies, poles that are determined to have reached the end of their useful life or that have sustained damage, are scheduled for replacement each year. These annual costs are not project specific but represent change out of individual poles as required.

18. Patrick Street Re-build – Nottawasaga to Brant ($228,000 scheduled for completion in 2010) – Preliminary work on this project was started in 2006, however the majority of work and costs for this project are expected to be incurred in late 2009 and 2010 and will be put in service in 2010. OPDC is planning to begin this project in May, with completion

scheduled for June. This project involves upgrading outdated equipment that has passed its useful life and includes replacement of 18 poles and all the related conductor and devices. To allow for anticipated increases in future loading, the new conductor will be larger than that which is being replaced.

19. Reconstruct Rear of BDO Dunwoody ($100,000 scheduled for completion in 2010) – Some preliminary / planning work on this project was undertaken in 2007, however the majority of work and costs for this project are expected to be incurred in 2010. OPDC is planning to begin this project in June, with completion scheduled for July. This project involves replacement of assets that have passed the expected useful life. There are five poles that require replacement as well as the related conductor and devices.

20. Westmount Drive – Coldwater to Mississaga ($180,000 in 2009) – The scope of this project involved relocation of an existing pole line in order to accommodate a city road widening and reconstruction.

21. Colborne Re-build – West to Andrew ($189,000 in 2010) – As a result of city-driven inter-section and road reconstruction, this project is being carried out and will result in relocation and upgrading 10 poles and the associated conductor and devices. OPDC is planning to begin this project in April, with completion scheduled for May.

22. Line 15 North – Pick Up Load Transfer Customers ($184,000 scheduled for completion in 2010) – This project is planned to be completed in two phases, beginning in 2009 and expected to be complete in 2010. The work to be completed in 2010 is scheduled for August. This project is driven by Section 6.5.4 of the DSC (revised July 24, 2008) requiring geographic distributors to eliminate their Long Term Load Transfer arrangements before January 31, 2009. OPDC's license was amended to grant an exemption from the requirements of section 6.5.4 of the DSC until January 31, 2011.

Capital plans to connect its LTLT customers to its distribution system were already approved before the most recent revision to the DSC June 16, 2009 extending the deadline for elimination of LTLT arrangements to June 30, 2014.

23. Proximity Issues – Mississaga & Andrew – Distribution Overhead ($125,000 in 2009) – The project scope was to replace existing construction that was not compliant with today's more stringent standards, in particular related to proximity conductor to buildings (ESA regulation 22/04 – Proximity to Structures).

Capital Expenditure Analysis _ Distribution Services:

DISTRIBUTION SYSTEM SERVICES __ GL # 1855		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
SERVICES __ GL # 1855								
O/H Services NEW	**22-YR-0003**	1,300	1,200	1,000	2,600	1,100	3,000	**3,000**
O/H Services REPLACEMENT	**22-YR-0004**	7,100	7,100	4,000	3,000	3,900	6,000	**6,000**
New U/G Services	**22-YR-0012**	18,900	17,700	16,700	22,800	26,700	20,000	**21,000**
Subdivision Installations_Services	**22-YR-0042**	177,900		84,900			30,000	**30,000**
		205,200	**26,000**	**106,600**	**28,400**	**31,700**	**59,000**	**60,000**

1. Subdivision Installations _ Services ($178,000 in 2004) – OPDC assumed four different subdivision developments with a total asset cost of $354,000 in 2004. The portion of this cost related to Services was $178,000. Through the economic evaluation process, $71,000 was paid to the developers, resulting in contributed capital of $107,000.

2. Subdivision Installations _ Services ($85,000 in 2006) – OPDC assumed two different subdivision developments with a total asset cost of $238,000 in 2006. The portion of this cost related to Services was $85,000. Through the economic evaluation process, $29,000 was paid to the developers, resulting in contributed capital of $56,000.

Capital Expenditure Analysis _ Distribution Underground:

DISTRIBUTION SYSTEM UNDERGROUND __ GL # 1840		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
UNDERGROUND __ GL # 1840								
Primary replacement	**22-YR-0011**	22,500	20,500	144,200	9,900	55,900	19,000	**46,000**
Install duct on Harmon Ave	**22-05-1541**					49,300		
Relocate traffic light controller - Front/Coldwater	**22-05-1542**				5,000			
Install duct on Brewery Lane	**22-05-1543**		48,300	2,300				
Install duct and recable Lankin Blvd	**22-05-1544**		145,400					
Install duct and recable Victoria Cres	**22-05-1545**		34,200					
Victoria/Lankin to Riser Cable Upgrade	**22-06-1564**			49,300	8,000			**123,000**
Atherley Rd 600A Loop Sys - Couch/Orchard Pts	**22-03-1504**	9,400						
Subdivision Installations_Underground	**22-YR-0040**	107,600		117,500			36,000	**36,000**
Ducts - Raymond St subdivision	**22-07-1583**				115,200			
Re-Cable Raymond St subdivision	**22-09-1614**						155,000	
Switchgear Upgrade	**22-08-1608**					109,900		
Duct MapleLeaf Cres	**22-10-NEW**							**26,000**
Duct King's Court	**22-10-NEW**							**39,000**
Duct Lahay Ave	**22-10-NEW**							**11,000**
Other capital expenditures		(24,500)	(210,000)	300				
		115,000	**38,400**	**313,600**	**138,100**	**215,100**	**210,000**	**281,000**

1. Primary Replacement ($144,000 in 2006 & $56,000 in 2008) - Costs in this category typically represent the replacement and upgrade of existing primary cables as they have reached the end of their useful life. The costs vary on an annual basis as they include costs of proactive or pre-planned cable replacements, in addition to replacement of cables following a failure of existing underground wires. These annual costs are not project specific but represent change out of underground cables as required.

2. Install Duct and Re-Cable Lankin Blvd. ($145,000 in 2005) – This project was undertaken to upgrade the existing direct buried cable with new ducts and cables. By carrying out this project there would be significant improvements in reliability to the customers in this service area as the existing cable had surpassed its' expected useful life.

3. Victoria / Lankin to Riser - Cable Upgrade ($123,000 planned for 2010) – This project involved an upgrade to the existing direct buried cable with new ducts and cables. By carrying out this project there would be significant improvements in reliability for the customers in this service area as the existing cable had surpassed its' expected useful life and was beginning to cause outages. OPDC is planning to begin this project in August, with completion scheduled for September.

4. Subdivision Installations _ Underground ($108,000 in 2004) – OPDC assumed four different subdivision developments with a total asset cost of $354,000 in 2004. The portion of this cost related to Underground was $108,000. Through the economic evaluation process, $44,000 was paid to the developers, resulting in contributed capital of $64,000.

5. Subdivision Installations _ Underground ($118,000 in 2006) – OPDC assumed two different subdivision developments with a total asset cost of $238,000 in 2006. The portion of this cost related to Underground was $118,000. Through the economic evaluation process, $37,000 was paid to the developers, resulting in contributed capital of $81,000.

6. Install Ducts – Raymond Street Subdivision ($115,000 in 2007) – As a result of inspections that form part of OPDC's Asset Management Plan and analysis of reliability measures, it was determined that the existing direct buried cable in this subdivision required upgrading. In 2007, the first phase of this project was undertaken and involved installation of the underground ductwork to house the new cable, that would be installed in 2009.

7. Re-Cable Raymond Street Subdivision ($155,000 in 2009) – Installation of the new cable was the second phase of the project noted above and was undertaken to ensure reliable service to customers in this service area by replacing existing plant that had reached its' expected useful life.

8. Switchgear Upgrade ($110,000 in 2008) – The scope of this project was to install five stainless steel switchgears in the underground section that runs along Atherley Road. The previous equipment suffered excessive corrosion due to its proximity to the road and the effects of road salt. This was the motivation to upgrade to stainless steel units. In addition, the project will provide enhanced system reliability in the future.

9. Surge Arrestor Returned to Inventory ($24,500 credit in 2004) – In 2004 it was discovered that a surge arrestor that had been charged out to an underground capital job in a previous year, had in fact been returned to inventory and not put in service. OPDC adjusted the capital account by the appropriate amount to reflect a true picture of the original job cost.

10. Reverse Accrual for Atherley Road Underground ($210,000 credit in 2005) – In 2005, it was determined that an accrual, previously established to estimate expected sub-contractor costs on an underground project along Atherley Road, would not materialize into actual costs. As a result, the accrual was reversed to reflect an accurate balance within the asset account and an entry to reverse all depreciation related to this accrued amount was booked.

Capital Expenditure Analysis _ Computer Hardware & Software:

OTHER CAPITAL ASSETS COMPUTER EQUIPMENT __ GL # 1920/25		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
COMPUTER EQUIPMENT_Hardware	**1920-00**							
Upgrade to Microsoft Exchanger/Windows 2003			42,600					
Cisco Router			8,100					
Document Management System							10,000	
Engineering - Plotter								**10,000**
Photocopier / Printer / Scanner							5,000	
Workstation hardware upgrades		1,800	16,000	11,700	12,600	6,800	20,000	**15,000**
		1,800	**66,700**	**11,700**	**12,600**	**6,800**	**35,000**	**25,000**
COMPUTER EQUIPMENT_Software	**1925-00**							
Conversion to Harris Billing System			164,400					
Upgrade to Microsoft Exchanger/Windows 2003			11,900					
Document Management System							50,000	
USF - Automated Solutions - WESys (Work Estimate System)				7,400	7,500			
Interface - Cablecad & Harris				2,700				
Great Plains software upgrade			1,800	15,000	7,000			**32,000**
Great Plains - Fixed Asset Module						10,600	3,000	
			178,100	**25,100**	**14,500**	**10,600**	**53,000**	**32,000**
		1,800	**244,800**	**36,800**	**27,100**	**17,400**	**88,000**	**57,000**

1. Conversion to Harris Billing System ($164,000 in 2005) – Prior to 2005, OPDC utilized the Advanced billing system software and housed its billing server within its administration offices at 360 West Street in Orillia. The decision to convert to the Harris billing system was impacted by a number of items. At the time, OPDC was moving towards a model of outsourcing the majority of its information technology (IT) functions. This move provided cost savings, improved IT reliability and significant improvements for system backups and disaster recovery planning. The Harris software program through its licensed distributor was a very good fit with the outsourced IT model OPDC was pursuing, including remote location of its billing server. In addition, OPDC would recognize significant annual cost savings for maintenance and support by transitioning from Advanced to Harris.

2. Document Management System ($10,000 hardware plus $50,000 software in 2009) – This project was planned in order to realize incremental efficiency gains within the office. The system will be utilized to provide an organized methodology for digital storage and retrieval of documents and drawings that are utilized by staff in engineering, finance, billing, regulatory and administration functions. In addition to providing ready access to documents that are currently stored in hard copy format in various secured locations, the document management system will be integrated with OPDC's existing billing system to improve customer service through improved access to customer information and account history.

Capital Expenditure Analysis _ Rolling Stock & Equipment:

OTHER CAPITAL ASSETS TRANSPORTATION EQUIPMENT __ GL # 1930		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
TRANSPORTATION EQUIPMENT __ GL # 1930								
Rolling Stock	**22-YR-0013**	278,000	29,900	129,900	31,000	520,900	250,000	**82,000**
Other capital expenditures								
		278,000	**29,900**	**129,900**	**31,000**	**520,900**	**250,000**	**82,000**
Rolling Stock 2009								
New Service Truck (Single bucket / material handling)							250,000	
Rolling Stock 2010								
2 New 3/4 Ton pick ups Replacing truck 4 & 18								**82,000**

1. Rolling Stock ($278,000 in 2004) – This expenditure represents the purchase of one 2004 Freightliner / Posi-Plus bucket truck. This new vehicle replaced truck #22 (vintage 1991) that was deemed to be at the end of its useful life. In addition, the replacement vehicle has several features that will improve worker safety, efficiency and provide additional functionality in the field.

2. Rolling Stock ($130,000 in 2006) – This expenditure represents the purchase of two vehicles. A 2006 Chevrolet 4X4 to replace truck #19 (vintage 1998) was purchased for $37,000. It also includes the purchase of a 2007 Freightliner dump truck for $93,000. The dump truck replaced truck #8 (vintage 1990) that had surpassed its expected useful life.

3. Rolling Stock ($521,000 in 2008) – This expenditure represents the purchase of one vehicle, a new pole trailer and significant upgrades / improvements to two other vehicles within the fleet. A 15-ton, radial boom derrick with a flatbed was purchased to replace two existing fleet vehicles, truck #11 a radial boom derrick (vintage 1988) and truck #14 a flat bed with Hiab crane (vintage 1986). It was determined that a single vehicle that possessed the additional functionality and safety features of the new vehicle, was a cost effective solution as opposed to purchasing two replacement vehicles. The new pole trailer was required to safely accommodate and transport the larger sized poles that are often utilized in OPDC's subtransmission lines and satisfy ESA and MTO requirements. Significant body refurbishment and paint work for truck #23 a radial boom derrick and the Bombardier track vehicle, also a radial boom derrick were carried out in 2008 and will extend the useful life of these vehicles.

4. Rolling Stock ($250,000 in 2009) – This expenditure represents the purchase of a 50-foot, single bucket truck with material handling capabilities to replace truck #20, a 36-foot single bucket truck (vintage 1996). The existing service truck has surpassed its expected useful life and lacks the functionality and safety features that exist on newer models.

5. Rolling Stock ($82,000 planned for 2010) – This expenditure represents the purchase of two pickup trucks to replace trucks #4 – pickup truck (vintage 2000) and #18 – pickup truck (vintage 1998). Both vehicles being replaced have surpassed their expected useful lives, are becoming more costly to maintain and less reliable. OPDC expects to take delivery of these trucks in July.

Capital Expenditure Analysis _ SCADA:

OTHER CAPITAL ASSETS SYSTEM SUPERVISORY EQUIPMENT _ GL # 1980		ACTUAL 31-Dec-04	ACTUAL 31-Dec-05	ACTUAL 31-Dec-06	ACTUAL 31-Dec-07	ACTUAL 31-Dec-08	PROJECTION 31-Dec-09	BUDGET 31-Dec-10
SCADA __ GL # 1980								
SCADA System Upgrade	**22-08-0009**					207,700		
						207,700		

1. Prior to the 2008 upgrade, OPDC's SCADA system ran on a VMS platform, which is not Windows compatible. This technology was becoming very outdated and acquiring system support was becoming increasingly costly and difficult to obtain. In fact, the IT vendor providing technical support warned OPDC that in the near future, support services would no longer be available for the system. The move to a Windows based solution addressed this issue, in addition to proving significant improvements to system reliability, data collection, reporting potential and available technical support services.

CAPITALIZATION POLICY

OPDC's Capitalization Policy follows below as Exhibit 2, Tab 4 Schedule 2:

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1. Definition of an Asset

CICA Handbook paragraph 1000.29 defines assets as economic resources controlled by an entity as a result of past transactions or events from which future economic benefits may be obtained. Assets have three essential characteristics:

1. They embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows and in the case of not-for-profit organizations, to provide services.

2. The entity can control access to the benefit.

3. The transaction or event giving rise to the entity's right to, or control of, the benefit has already incurred.

In addition, in identifying a benefit there must be:

A. An ability to earn income or supply a service.

B. A reasonable expectation that the benefit will be provided in future periods.

C. The future period must be identifiable and greater than one year.

The CICA Handbook specifically defines a capital asset as identifiable assets comprising property, plant and equipment and intangible properties that meet all of the following criteria:

1. Are held for use in the production of supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair to other capital assets.

2. Have been acquired, constructed or developed with the intention of being used on a continuing basis.

3. Are not intended for sale in the ordinary course of business.

2. Capitalizing Upgrades and Improvements – "Betterments"

Betterment is defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when:

- there is an increase in previously assessed physical output or service capacity,
- associated operating costs are lowered,
- the life or useful life is extended, or
- quality of output is improved.

Betterments increase service potential (and may or may not increase the useful life of a tangible capital asset). Such expenditures would be included in the cost of the related asset.

Maintenance and repairs maintain the predetermined service potential of a tangible capital asset for a given useful life. Such expenditures are expenses in the period in which they are made. A repair or replacement is comprised of the repair of an existing component, or the replacement of an existing component with a similar component.

3. Capitalization Threshold

Theoretically, any item that meets the definition and recognition criteria would be recorded as a tangible capital asset. In practical terms, the Company shall treat as a capital asset, any asset that in addition to the above conditions, has a useful life in excess of one year and a per item cost greater than $1,000. This threshold may be changed at the discretion of the CFO / Treasurer and on an item-by-item basis, if it is deemed appropriate to capitalize an amount lower than the amount prescribed above in order to ensure all material capital assets are included in the financial statements. Assets below the threshold are expensed in the period of purchase.

Land will always be capitalized, regardless of cost.

In assessing any particular expenditure to determine whether it is appropriate to treat it as a repair (expense) or betterment (capitalize), the following schedule of characteristics may be helpful in guiding the decision:

Characteristics to Consider

Repairs = Expense	Betterments = Capital Assets
All items – life less than 1 year	Life of more than 1 year
All items under $1,000	Items greater than $1,000
Replacement of individual components of a TCA due to age, “wear-and-tear” and damage in order to maintain the TCA in an operating condition without significantly enhancing functionality, capacity, usability and efficiency	Replacement of motor and parts that prolong the useful life
Renovations – carpeting, painting, etc.	The estimated life of the asset is extended by more than 25%
System and equipment repairs, in cases where the service potential of a building isn’t enhanced, repairs – boilers, elevators, control system, etc.	The cost results in an increase in the capacity of the asset
Building repairs that are required in the normal maintenance process	The efficiency of the asset is increased by more than 10%
Repairs to restore assets damaged by fire, flood or similar events, to a condition just prior to the event	Significantly changes the character of the asset
	Reduction in operating cost

ASSET MANAGEMENT

OPDC is guided in its asset management philosophy by our mission statement that requires maintenance of the highest standards for public and staff safety, reliability of supply, protection of the environment and first class customer service.

A copy of OPDC's asset management plan has been attached as Appendix 2-A. Appendix 1-H in Exhibit 1 summarizes OPDC's capital expenditure plans from 2010 to 2015 by function (land, buildings, poles, wires etc.). Table 2-18 summarizes capital expenditure plans from 2010 to 2015 by project drivers.

Table 2-18: Capital Expenditure Plans from 2010 to 2015 Summarized By Project Drivers

Project Drivers	2010	2011	2012	2013	2014	2015
Aging Assets	1,305,000	2,056,000	838,000	1,418,000	1,770,000	1,765,000
Reliability	136,000	340,000	225,000	190,000	80,000	50,000
Growth / Customer Demand / Capacity	273,000	165,000	920,000	170,000	175,000	175,000
Totals	**$1,714,000**	**2,561,000**	**$1,983,000**	**$1,778,000**	**$2,025,000**	**$1,990,000**

Orillia Power Distribution Corporation (OPDC) is an infrastructure-based business with its distribution system assets forming the key element in the delivery of electricity to its existing and new customers. OPDC owns and operates the electricity distribution system with the licensed territory of 27 square kilometers within the City of Orillia, serving approximately 12,800 customers. As of January 1, 2009, OPDC had approximately 245 kilometres of overhead circuits, 58 kilometres of underground circuits, 10 Distribution stations and 1,756 transformers operating within the system. OPDC assets range in age from new to over 50 years old. OPDC employs 9 full-time line personnel and utilizes qualified contractors to provide additional distribution plant services as required.

OPDC's Asset Management Plan provides the framework for professional management of its physical infrastructure, with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The company utilizes information gathered through various inspection and maintenance efforts listed in the plan, to help in the development of its annual capital budget. Regular review of the status of service quality indicators highlights areas where further investigation and system improvements may be required. Finally, community growth and development projects driven by the City of Orillia, impact the capital planning and undertakings by the Company.

Acts, Regulations, Codes & Guides:

In fulfilling its obligations to efficiently and effectively manage its distribution system, OPDC must comply with many varied acts, regulations, codes and guidelines. Some of these (not all inclusive) are as follows:

- The Ontario Energy Board ("OEB") is a principal regulator guiding OPDC's operating and business practices. Under the guiding principles set out in the *Electricity Act, 1998* (the "Electricity Act"), the OEB has established a Distribution System Code ("DSC") that defines how and under what conditions, a utility is to provide service and interact with its customers. It is prescriptive in nature and deals with virtually every aspect of utility operations including such things as: connections and expansions, standards of business practice and conduct, quality of supply (reliability), infrastructure inspections, metering and conditions of service. The licensed distributor's conditions of service are set out by the distributor in a document that is filed with the OEB and posted on the distributor's web site.

- The Electrical Safety Authority ("ESA") also derives its authority from the Electricity Act. The ESA is responsible for ensuring the safety of all electrical installations in the province of Ontario. Before Bill 35 restructuring, distributors were not governed by ESA. This changed with the passing of the restructuring legislation and now the ESA oversees the work of the Local Distribution Companies (“LDCs”). Under regulation 22/04, every electrical installation and associated equipment must be installed in accordance with a design or standard approved by a professional engineer. Every year there is a compliance audit conducted by an outside agency and the utility is required to sign a regulatory declaration stipulating that it has complied with the regulations.

- The Occupational Health and Safety Act (“OHSA”) governs how work is performed and is enforced by the Ministry of Labour. The act is comprehensive and forms part of every job. At OPDC, the health and safety of employees and customers is given the very top priority and there is an active joint health and safety committee that oversees operational activities. Extensive training programs ensure that staff is competent to perform their duties. Every effort is made to make sure that employees have the right tools and protective equipment to do their job safely.

- The Ministry of Environment (“MOE”) is responsible for regulating how hazardous waste is handled. OPDC has a registered hazardous waste storage site for PCBs on our property.

- Measurement Canada (“MC”) dictates the requirements of the revenue metering activities. There is a strict compliance requirement and audits occur each year.

- The Ministry of Transportation (“MOT”) is the governing body with respect to activities associated with the fleet. It also mandates the requirements for traffic control at worksites that are near or on roadways.

- There are a host of other entities that mandate programs and work practices. These include, but are not limited to: the Electrical Utility Safety Association ("EUSA"); the Independent Electric System Operator ("IESO"); the Professional Engineers Ontario ("PEO"), the Canadian Institute of Chartered Accountants ("CICA") and the Canadian Standards Association ("CSA").

All of the above acts, regulations, codes and guidelines impact planning and work processes, and must be complied with to ensure that OPDC follows "Good Utility Practice".

As an example, a copy of OPDC's most recent ESA 22/04 inspection report has been attached as Appendix 2-B. The purpose of including this report is two-fold. A review of the report indicates and reinforces the numerous compliance requirements that only one area of regulation imposes on all LDCs. Secondly, this audit report, with its fully compliant rating, supports the fact that OPDC's asset management plan is effective and achieving its goals.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

Service quality and reliability indicators were presented in Exhibit 1 however, to ensure completeness of Exhibit 2 are repeated here.

Table 2-19 lists customer service indicators for 2005 through to 2008 compared to the required OEB minimum standard. OPDC's mission is to consistently maintain high customer service standards and has done so as can be seen by a review of the table below.

Table 2-19: Service Quality Indicators 2005 to 2008 - CUSTOMER SERVICE

Customer Service	Minimum Standards	2005	2006	2007	2008
Connection New Services - Low Voltage within 5 working days	90% or better	100.00	100.00	100.00	100.00
Connection New Services - High Voltage within 10 working days	90% or better	N/A	N/A	N/A	N/A
Underground Cable Locates - within 5 working days	90% or better	100.00	100.00	100.00	100.00
Appointments Met - at the appointed time	90% or better	100.00	100.00	100.00	100.00
Telephone Accessibility - answered in person within 30 seconds	65% or better	96.75	100.00	98.10	98.50
Written Response to Inquiries - within 10 working days	80% or better	N/A	N/A	100.00	100.00
Emergency Response - Urban within 60 minutes	80% or better	100.00	100.00	100.00	100.00
Emergency Response - Rural within 120 minutes	80% or better	N/A	N/A	N/A	N/A

Table 2-20 presents reliability indicators for 2005 through 2008. The chart presents SAIDI, SAIFI and CAIDI statistics for all interruptions (1) and interruptions excluding loss of supply (2). OPDC is embedded within Hydro One's system and as such can not control loss of supply so will focus its comments on the reliability factors that exclude loss of supply (2). As can be seen from the Table and the graph that follows, OPDC has performed consistently in this area over the last four years. The statistics are higher in 2007 for specific weather related events. The City of Orillia experienced some severe weather in June 2007 taking down numerous trees and power lines. In December 2007, a significant winter storm resulted in the temporary loss of a main feeder line due to ice damage.

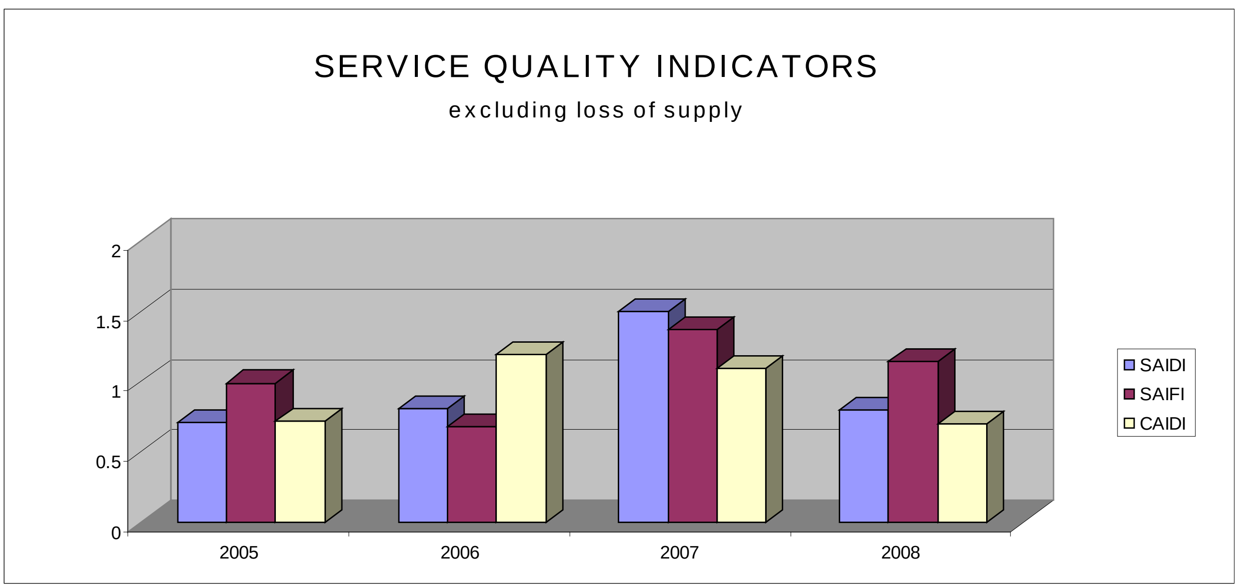
OPDC has also compared our statistics to other LDCs for reliability and while there is always room for improvement, it appears OPDC is performing well relative to other LDCs. OPDC participates in a performance benchmarking survey with the MEARIE Group each year along with about forty of the 80 plus LDCs in the province. OPDC is in the first quartile among 40 MEARIE reporting LDCs for SAIDI at 0.80 (MEARIE 0.86). This confirms that OPDC has been successful in responding quickly and keeping outages short.

OPDC is in the in the second quartile for SAIFI at 1.14 and has a better than average statistic compared to the other reporting LDCs (MEARIE third quartile is 1.60 and mean is 1.53). OPDC frequency of outages has climbed slightly the last two years and as a result dropped out of the first quartile in that category. As can be seen in our comments on capital expenditures, OPDC continues to focus on improving reliability through upgrades and enhancements to our system.

OPDC’s mission is to consistently maintain high standards for reliability of supply and we will continue to strive towards that goal.

Table 2-20: Service Quality Indicators 2005 to 2008 - RELIABILITY

Reliability	Minimum Standards	2005	2006	2007	2008
Service Quality - (1) All Interruptions:					
SAIDI - System Average Interruption Duration Index (Hours per Customer)	Compared to previous 3 yrs	1.57	1.65	5.36	1.69
SAIFI - System Average Interruption Duration Index (Interruptions per Customer)	Compared to previous 3 yrs	1.63	1.62	3.60	2.27
CAIDI - System Average Interruption Duration Index (Hours per Interruption)	Compared to previous 3 yrs	0.97	1.02	1.49	0.74
Service Quality - (2) All Interruptions excluding loss of supply (Cause Code 2):					
SAIDI - System Average Interruption Duration Index (Hours per Customer)	Compared to previous 3 yrs	0.71	0.81	1.50	0.80
SAIFI - System Average Interruption Duration Index (Interruptions per Customer)	Compared to previous 3 yrs	0.99	0.68	1.37	1.14
CAIDI - System Average Interruption Duration Index (Hours per Interruption)	Compared to previous 3 yrs	0.72	1.19	1.09	0.70



		Units of Measure
SAIDI	"System Average Interruption Duration Index"	Hours per Customer
SAIFI	"System Average Interruption Frequency Index"	Interruptions per Customer
CAIDI	"Customer Average Interruption Duration Index"	Hours per Interruption

APPENDIX 2 – A

OPDC’s Asset Management Plan follows in the next twenty-one pages.

Orillia Power Distribution Corporation

Asset Management Plan

ORILLIAPOWER

Energizing Our Community

Orillia Power Distribution Corporation

Asset Management Plan

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Orillia Power Distribution Corporation

Asset Management Plan

Overview

Orillia Power Distribution Corporation (OPDC) is an infrastructure-based business with its distribution system assets forming the key element in the delivery of electricity to its existing and new customers. OPDC owns and operates the electricity distribution system with the licensed territory of 27 square kilometers within the City of Orillia, serving approximately 12,800 customers. As of January 1, 2009, OPDC had approximately 245 kilometres of overhead circuits, 58 kilometres of underground circuits, 10 Distribution stations and 1,756 transformers operating within the system. OPDC assets range in age from new to over 50 years old. OPDC employs 9 full-time line personnel and utilizes qualified contractors to provide additional distribution plant services as required.

OPDC's Asset Management Plan provides the framework for professional management of its physical infrastructure, with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The company utilizes information gathered through the various inspection and maintenance efforts listed below, to assist in the development of its annual capital and operating budgets. When categorizing work as capital or maintenance, the company applies its Capitalization Policy, to ensure that costs are budgeted and recorded appropriately. In addition, regular review of service quality indicators, highlight areas where further investigation and system improvements may be required. Finally, community growth and development projects driven by the City of Orillia, impact the capital planning and undertakings by the Company.

Overhead

Line Patrol and Pole Inspection

Line patrols and pole inspections are carried out in order to highlight equipment that requires maintenance, identify potential safety issues and also to identify areas for future upgrade or improvements. Formal inspections of the entire overhead system are performed on a three year cycle. Further patrol and inspection efforts are carried out by line and engineering staff as they travel throughout our service territory and during tree trimming work. In addition, issues and potential trouble spots are also identified by our SCADA system and occasionally from customer calls.

Pole Testing

OPDC has approximately 6,300 poles within its distribution system. Extensive monitoring and experience has proven that Western red cedar poles provide the highest level of durability and cost effectiveness in the weather and environmental conditions for the service area. Although Western red cedar is utilized for all new pole installations, OPDC also has red pine, jack pine and a minimal number of concrete poles currently in use within the system. A comprehensive cycle of testing for all OPDC poles is scheduled for completion by the end of 2009. The testing process measures the resistance or density of the wood, along with the internal moisture. The test data is loaded into analysis software which performs the supporting calculations and provides an output that summarizes remaining life expectancy of each pole and timeline for re-testing.

Ground Rod Conductivity Verification

Ground rods are tested in conjunction with our pole testing cycles. They are tested for conductivity and if a reading in excess of 25 ohms is recorded, corrective action is taken; including examination of all connections and potentially replacement of the ground rod if required. Ground rods are utilized on poles where transformers, switches or other devices are located.

Tree Trimming

OPDC takes a very proactive approach with respect to tree trimming in order to maintain a high level of system reliability, protect our assets from damage, reduce outages and to protect public and worker safety. Tree trimming work is carried out on a three year cycle and covers the entire service area of OPDC. This work is carried out by both in-house staff as well as qualified contractors. Our extensive tree trimming efforts also provide an opportunity to carry out significant system inspections, as noted above.

Load Interrupter Maintenance

There are currently 17 load interrupters utilized throughout OPDC's distribution system. These devices enable the company to effectively manage its system and transfer loads as required. Following a three year cycle, maintenance work on load interrupters helps to ensure a high level of reliability. In the event that a previously utilized load interrupter is being put back into service, it is first sent back to the manufacturer for re-verification. New equipment is purchased in the case where repairs or re-verification is not possible and also in instances of community growth or development.

Air Break Switch Maintenance

Maintenance of air break switches is done on a five year cycle. OPDC currently has 40 switches within its 44 kV system (29 air brakes and 11 load interrupters) and has embarked on a program of replacing 44kV air break switches with 44kV load break switches. This transition will happen gradually over the coming years and is driven by the goal of achieving increased reliability, reduced maintenance requirements and the capability to control load break switches remotely as opposed to manually. In the event that a previously utilized air break switch is being put back into service, it is first sent back to the manufacturer for re-verification.

Infrared Scanning

Infrared scanning is another proactive measure that is utilized by OPDC in order to maintain the distribution system and assist in planning required maintenance work. The scanning process will identify ‘hot spots’ throughout the system, which are typically indicative of underlying issues that require attention. Infrared scanning inspections are carried out annually on the overhead system.

Inspection of Customer Owned Substations

OPDC staff perform a visual inspection of all customer owned substations on an annual basis. Any potential issues or problems are reported to the customer for further investigation and corrective actions.

Distribution Transformers

Overhead transformers are inspected on a three year cycle as part of the regular inspection process. Through the normal course of business, transformers are occasionally brought back in-house and then subsequently put back into service. This could be due to a transformer upgrade, provision of a temporary service or numerous other scenarios. Prior to a transformer being put back into service, the normal process includes a ratio check; which measures the voltage ratio between the windings of the transformer, a continuity check and PCB & oil sample testing.

Substations

Inspection

OPDC operates 10 distribution substations within its service territory. On a monthly basis, a physical inspection of each substation is carried out by qualified OPDC staff members. These monthly inspections provide a general overview of the substation condition and provide an opportunity to identify potential problems early on. These inspections also verify that there is no damage or issues with perimeter fencing, which could lead to a public safety issue. More detailed inspection routines for specific equipment within the substations are detailed below.

Circuit Breakers

Circuit breaker inspections are carried out on a three year cycle by OPDC staff. In the event that a breaker requires refurbishing, that work is sub-contracted to a qualified vendor.

Relay Re-verifications

OPDC staff verifies the functionality and settings for all relays on an annual basis. Any adjustments to the settings are outsourced to a qualified engineering firm.

Oil Sampling and Gas Analysis

On an annual basis, oil samples are taken and analysis is performed on the samples for each power transformer. The analysis is done by a qualified subcontractor to ensure that the readings are within the appropriate thresholds. If required, remedial action is undertaken to ensure proper continuing operation of the substation.

Battery Banks

Battery banks at each substation are critical for communication and operation of the substation. Once each year, the battery banks are inspected to ensure they are retaining an adequate charge and are operating reliably. When it is identified that a particular battery bank is losing its ability to hold a charge or there are reliability issues identified, it will be scheduled for replacement.

Thermographic Inspections

Annual thermographic inspections of substations are a preventive maintenance tool that is utilized to provide early identification of potential problems within the substations. Performed by a qualified contractor, these inspections identify ‘hot spots’ within the substation that could indicate equipment problems and allow OPDC staff to focus further investigation in the appropriate area.

Vegetation Control and Snow Removal

A critical component of the maintenance of substations is the timely removal of snow and excessive vegetation around the substation properties. This ensures unimpeded access to equipment for maintenance activities in addition to reducing the risk of snow affecting equipment performance. Furthermore, vegetation control is utilized to preserve the integrity of the station ground grids, thereby enhancing the safety for OPDC staff, in compliance with Electrical Safety Authority (ESA) regulations.

Underground

For all new commercial, industrial and residential subdivision development within the service territory, services are being placed underground. For all new subdivisions, fault indicators are utilized to improve OPDC's ability to rapidly identify and sectionalize faults, thereby reducing outage times and improving overall efficiency in the maintenance of underground plant. In order to improve system reliability, existing direct buried primary cables in older subdivisions are being ducted for future upgrade. Furthermore, to improve public safety, system security and reliability; rear lot overhead primary lines are gradually being converted to underground. This project is expected to continue into the foreseeable future and replacement is prioritized based on the condition of the existing plant and the assessment of potential safety risks.

Switchgear Inspections

Inspections of all OPDC switchgears are carried out on a three year cycle. In order to prolong the life of the asset, switchgears are painted regularly based on the condition observed during the inspection process. In the event that a switchgear is being re-deployed in the field, it would first be sent to the manufacturer for re-verification.

Padmount Transformers

Padmount transformers are also inspected on a three year cycle. A proactive approach to painting transformers, implemented during the past several years, has proved to be effective in maintaining and prolonging the life of the assets in addition to improving safety factors. New transformer purchases are driven by community expansion and replacement of obsolete or defective units.

Infrared Scanning

Infrared scanning of switchgears, padmount transformers and K-Bar units (switching cubicles) is utilized to identify potential trouble spots and highlight to staff where further investigation and maintenance may be required. This scanning is carried out on a three year cycle.

Underground Vault Inspections

OPDC staff perform underground vault inspections a minimum of two times per year. This regular inspection process enables the Company to take proactive steps in the event that any issues or problems are identified during the inspection process.

SCADA

Initial troubleshooting and issue identification for any SCADA problems is carried out by OPDC staff. If additional expertise is required, we rely on maintenance contracts with qualified vendors for both hardware and software.

Meters

In the past, conventional meters have had a seal period between six and twelve years. The Customer Information System is utilized to track the expiration of seal periods and to plan the timing of meter re-verifications. Re-verification work is carried out by a qualified contractor and once successfully completed, meters will be redeployed as required. With the planned implementation of smart meters in 2010, OPDC will incur a one-time significant capital expenditure to replace all the meters within the system. Given that the smart meters will all be brand new, we anticipate minimal meter replacement costs over the 5-year horizon.

Land

Requirements for new land acquisition typically arise as a result of community growth and development within the service territory that drives the need for system expansion. Based on OPDC's relationship with the City of Orillia and various developers, the Company will usually have significant advance warning of planned growth and therefore have plenty of time for assessing the growth plans and the impact on future distribution system demands. Based on the assessment and the careful consideration of the possible alternatives, the Company will proceed with the acquisition of land required to locate its distribution system assets.

Buildings

OPDC buildings are maintained by in house staff and various contractors; for services such as grass cutting, snow clearing, etc. Specific repairs that require a tradesperson or specialist are handled on an as needed basis. When it is deemed that significant building improvements and renovations are necessary, the Company prepares a detailed scope document and goes through a project tendering process. Any significant building improvements are reviewed on an annual basis as part of the normal budgeting process.

Vehicles

OPDC has an on staff mechanic who performs the majority of the maintenance activities on the fleet. If required, the vehicle manufacturer or outside mechanics would be utilized to perform maintenance that is outside the scope of in-house staff or requires special equipment.

As part of the annual budget process, an analysis of existing fleet is used to identify the need for replacement equipment or the need for new types of equipment to enable OPDC line staff to effectively and safely perform their duties. The fleet analysis also includes examination of maintenance and repair records and related costs. Surplus vehicles are traded in or disposed of to gain the greatest possible recovery for the Company.

Tools and Equipment

Capital tool and equipment purchases are planned during the annual budget preparation, except in cases where an unexpected failure or unforeseen development prompts a more timely decision to purchase. For all tools that require regular testing or calibration, OPDC follows the manufacturers' schedule to carry out these activities. Aside from pricing, the ergonomic qualities and expected life of the tools and equipment are major considerations in the purchasing process.

Computer Software and Hardware

Computer and technology based tools are critical to the efficient operation of the Company. OPDC staff works closely with our outside IT service provider to assess the needs of the Company and to implement technology solutions that are both cost effective and functional. Computer equipment maintenance is performed by a third party IT consultant. Decisions to replace equipment are typically driven by the need for improved speed, reliability issues with existing equipment, new technologies that require upgraded systems and equipment no longer supported by IT vendors. Purchasing decisions are part of the annual budget planning process.

Office Equipment and Furniture

Each year during the budgeting process, a review of office equipment needs is carried out to address the requirements for any upgrades, replacements or expansion.

Appendix A – OPDC Inspection Form Templates

See following pages for samples of inspection forms utilized by OPDC.

TRANSFORMER RE-VERIFICATION

Every transformer that gets returned to Stores from the field, before being accepted back into stock must have the following sheet completed

Transformer OR # ____________________ Year Manufactured ____________________
Green Sheet ____________________
Serial # ____________________ Primary Voltage ____________________

Manufacturer ____________________ Secondary Voltage ____________________

Transformer Test Results

Open	**Short**	**Pass**
☐	☐	☐

Insulator/Bushing Well Inspection

	OK	**Other**
X1	______	______
X2	______	______
X3	______	______
X0	______	______
H1A	______	______
H2A	______	______
H3A	______	______
H1B	______	______
H2B	______	______
H3B	______	______

Casing Inspection

	Yes	**No**
Dents	______	______
Surface rust	______	______
Rusted seams	______	______
Oil leaks	______	______
Defective hinges	______	______
Penta bolt	______	______

Oil sample taken ____________________ ppm of PCB's.

This transformer has been tested and inspected. Under "Good Utility Practice", this transformer is accepted into inventory for re-use in the Orillia Power Distribution Corporation's system.

____________________ ____________________ ____________________
Inspector Line Foreman (or designate) Date

Date ____________________

ORILLIA POWER
Energizing Our Community

ORILLIA POWER DISTRIBUTION CORPORATION
TRANSFORMER
Inspection Sheet/Trouble Report

TRANSFORMER NO. ________________ LOCATION: ______________________________

PRIMARY VOLTAGE ☐ 2.4 KV ☐ 8 kV ☐ 4 kV ☐ 13 kV

SECONDARY VOLTAGE ☐ 120/240 ☐ 120/208 ☐ 347/600

EXTERNAL INSPECTION:	OK YES	OK NO	*COMMENTS:* (INFARED PROBLEMS)
NOMENCLATURE	☐	☐	
PAINT	☐	☐	
LOCK	☐	☐	
LATCH MECH/BOLT	☐	☐	
DOOR HINGES	☐	☐	
CONCRETE PAD	☐	☐	
GRADE LEVEL/BASE	☐	☐	
METAL CABINET	☐	☐	
SIGNAGE	☐	☐	
OIL LEAKS	☐	☐	

INTERNAL INSPECTION:	OK YES	OK NO	
CABLE TERMINATIONS	☐	☐	
SECONDARY CONNECTIONS	☐	☐	
GROUNDING	☐	☐	
FAULT INDICATORS	☐	☐	
EXCESS MOISTURE	☐	☐	
EVIDENCE OF OVERHEAT	☐	☐	
OIL LEAKS	☐	☐	

AMP CHECKS

HOUSE #	READINGS		

COMPLETED BY: ______________________________ *DATE:* ____________________

ORILLIA POWER DISTRIBUTION CORPORATION

SWITCHGEAR

ORILLIAPOWER
Energizing Our Community

Inspection Sheet/Trouble Report

SWITCHGEAR NO ______________ LOCATION: ______________________________

PRIMARY VOLTAGE ☐ 2.4 KV ☐ 8 kV ☐ 4 kV ☐ 13 kV

COMMENTS: (INFARED PROBLEMS)

EXTERNAL INSPECTION:	OK YES	OK NO	Comments
NOMENCLATURE	☐	☐	______
PAINT	☐	☐	______
LOCK	☐	☐	______
LATCH MECH/BOLT	☐	☐	______
DOOR HINGES	☐	☐	______
CONCRETE PAD	☐	☐	______
GRADE LEVEL/BASE	☐	☐	______
METAL CABINET	☐	☐	______
SIGNAGE	☐	☐	______
OIL LEAKS	☐	☐	______

INTERNAL INSPECTION:	OK YES	OK NO	Comments
CABLE TERMINATIONS	☐	☐	______
GROUNDING	☐	☐	______
FAULT INDICATORS	☐	☐	______
EXCESS MOISTURE	☐	☐	______
EVIDENCE OF OVERHEAT	☐	☐	______
OIL LEAKS	☐	☐	______

COMMENTS

____

____

____

____

____

____

____

COMPLETED BY: ______________________ ***DATE:*** ______________

ORILLIA POWER
Energizing Our Community

Privately Owned Substation Maintenance Condition Report

Sub-Station Name/ Location____

Date of Inspection: ____

Items To Be Checked	Yes / No / NA	Comments
Station fence / enclosure, prevents unauthorized access and is in adequate condition		
Barbed wire is in place and in good condition		
Required warning signs are in place and legible		
No vegetation is present within fenced area		
Insulators are in good shape with no cracks, chips or deterioration (visual from ground)		
Transformer oil leaks apparent		
All nomenclature are installed on breakers and switches		
Are there objects or structures adjacent to the station creating a potential access or touch voltage hazard?		
Other		

Any items on or off the list requiring action: ____

____

____

Report Completed By: ____

(Print Name)

Signature: ____

ISOLATION DEVICE MAINTENANCE

DESIGNATION ______ DEVICE ______

NUMBER ______ SYS VOLT ______

ASSOC LINE ______ ASSOC STN ______

PHASE ______ AMPS ______

GEOGRAPHIC LOCATION ______

SWITCH TYPE	ONE PIECE	☐	THREE PIECE	☐
DEAD END TYPE	POLY	☐	PORCELAIN	☐
MTG CONFIG	VERTICAL	☐	HORIZONTAL	☐
BLADE OPER	VERTICAL	☐	HORIZONTAL	☐

CONN TYPE ______ JUMPER SIZE ______

HAND INSUL JUMPERED OUT	YES	☐	NO	☐
GR SPUDS	YES	☐	NO	☐

MFG ______ NOMINAL VOLTAGE ______

S/N # ______ CATALOG # ______

MFG DATE ______ DWG # ______ TYPE CAT # ______

INST DATE ______

COMMENTS

LAST MAINT DATE ______ COMPLETED BY ______

MAINT DATE ______ COMPLETED BY ______

NEXT MAINT DATE ______

ORILLIAPOWER
Energizing Our Community

SITE INSPECTION - LINE DEPARTMENT

JOB AT HAND: ____________ LOCATION: ____________

FOREMAN: ____________ VEHICLE: ____________

DATE: ____________

LEGEND: S - Satisfactory U - Unsatisfactory R - Recommendations

PROTECTIVE EQUIPMENT	S	U	R	REMARKS
Head				
Hand				
Eye				
Foot				
Ear				
Belt, Spurs,Lanyards				
Rubber Protection				
Line Grounds				
Protection Code				
Work Area Protection				
Clothing,Guards, Etc.				
Other				
VEHICLE & EQUIPMENT				
Truck Ground				
Boom Test				
Bucket Liners				
Tires,Lights, Asses.				
Ground Matt				
Outrigger Pads, Etc.				
Log Book Up-to-Date				
SAFETY ACCESSORIES				
Fire Extinguisher				
First Aid Kit				
Pole Top Rescue Rope				
Bucket Evac. Rope				
Rescue Rig				
Safety Blanket				
Rule Books				
Safety Practice Guides				
Safety Gas Cans				
Signs & Flags				
Spills Kit				
Wheel Chocks				
A.E.D. Weekly Inspections				
Truck #4, #18, & #20 Only				
Chain Saw Prot. Equip.				
GENERAL				
Housekeeping				
Safety Meetings				
Rescue & Resuscitation				
Tailboard Conference				
Other				
SUPERVISION				

TOOLS &EQUIPMENT	S	U	R	REMARKS
Live Line Tools				
Ladders				
Ropes				
Hoists				
Hand Tools				
Tool Guards				
Pole Jack				

OBSERVATIONS:

1. Unsafe Act

2. Unsafe Condtions

3. Other

GENERAL COMMENTS:

Ground to Ground Yes _____ No _____

Lock to Lock Yes _____ No _____

Inspected By: ____________

Inspected By: ____________

DISTRIBUTION:

Line Foreman ____________
Distribution Superintendent ____________
Human Resources ____________
ORIGINAL TO FILE

ORILLIAPOWER
Energizing Our Community

VAULT INSPECTION REPORT

Date of Inspection: ______________________

Completed By: ______________________

Vault Number: ____________ Vault Location: ____________________

	OK Yes	OK No
Lid Flush with Surface	☐	☐
Latching Mechanism	☐	☐
Hinges	☐	☐
Concrete Vault	☐	☐
Vault Requires Pumping	☐	☐
Equipment in Vault	☐	☐

APPENDIX 2 – B

OPDC's most recent ESA Audit Report follows on the next thirty-one pages.

ORILLIAPOWER
Energizing Our Community

Telephone: (705) 326-7315
Fax: (705) 326-0800

May 5, 2009

Electrical Safety Authority,
155A Matheson Blvd., West,
Suite 200,
Mississauga, ON
L5R 3L5

Attention: General Manager, Utility Regulation

Re: **AUDIT REPORT & DECLARATION OF COMPLIANCE**

Please find enclosed a copy of the ESA Audit Report, Action Plan for Improvement and OPDC's Declaration of Compliance. The time period subject to the Declaration of Compliance is March 1, 2008 to February 28, 2009.

Please contact me if you have any questions regarding this report or require any additional information.

Yours truly,

Ritchie Udell

Ritchie Udell,
Distribution Superintendent

RU:sla
Encl.

360 West St. S., P.O. Box 398, Orillia ON L3V 6J9 info@orilliapower.ca www.orilliapower.ca
John F. Mattinson, P.Eng. – President & Secretary
Patrick J. Hurley, B.Math, CMA - Treasurer

AESI
Acumen Engineered Solutions International Inc.

Canadian Office
775 Main Street East, Suite 1B
Milton, Ontario, Canada L9T 3Z3
Office: 905-875-2075
Fax: 905-875-2062

United States Office
7000 Central Parkway, Suite 1475
Atlanta, Georgia, USA, 30328
Office: 678-320-1895
Fax: 770-522-8115

e-mail: aesi@aesi-inc.com
website: www.aesi-inc.com

April 25, 2009

RECEIVED
APR 28 2009
ORILLIA POWER CORPORATION

Mr. Ritchie Udell,
Distribution Superintendent,
Orillia Power Corporation,
360 West St. S.,
Orillia, ON
L3V 5G8

Dear Ritchie:

Please find enclosed, two copies of my report on the OR 22/04 audit performed on April 23 and 24, 2009. No nonconformances nor opportunities were identified in this audit. One opportunity for improvement and one observation are noted in my report. Once more, an excellent job has been done.

ESA will request that you submit your audit report for review. The audit findings may be reviewed with ESA at a follow up meeting and any issues that require action may be discussed.

Thank you for your hospitality. I very much enjoyed working with you and your staff. I found everyone I encountered helpful, professional, forthcoming with information and generous with his or her valuable time.

Please contact me if you have any questions on this report or require any additional information.

Yours truly,

Les.

Leslie Stoch, P.Eng.

RECEIVED
APR 28 2009
ORILLIA POWER
CORPORATION

Audit Report
March 1, 2008 – February 28, 2009
Ontario Regulation 22/04
Sections 4 to 8

Orillia Power Corporation,
360 West St. S., Orillia, ON
L3V 5G8

Prepared by: Leslie Stoch **Date:** Apr. 25/09
L. Stoch, P.Eng.

Reviewed by: Ritchie Uddell **Date:** May 5, 2009

Description and Scope of Audit

An OR 22/04 audit of Orillia Power Corporation was carried out on April 23 and 24, 2009 by Les Stoch of L. Stoch and Associates. Its purpose was to assess the extent of compliance with respect to Sections 4 to 8 of Ontario Regulation 22/04, to measure whether the distributor has appropriate processes in place to comply with the safety standards set out in the regulation and whether the organization correctly follows its processes. This audit covers the period March 1, 2008 to February 28, 2009. It includes and assessment of the distributor's progress in addressing issues identified in the previous audit.

Orillia Power Corporation distributes electricity in the City of Orillia, serving approximately 13,000 residential, commercial and industrial customers. The scope of this audit involved processes concerning 11 municipal substations, 4160 volts to 44 kV, overhead and underground primary and secondary lines. The distributor is owned by the City and employs 43 staff.

The audit plan, shown in the attached audit checklist/report covers the distributor's policies and procedures concerning OR 22/04. Standard auditing methods and procedures were used including interviews with personnel, examining documents and records and observing work in progress on a relevant sample of work activities.

Although the emphasis of this audit was directed toward nonconformances and aspects that should be considered for improvement, nothing in this report should be construed as criticism of neither the distributor's staff nor the services provided.

Auditor Qualifications and Experience

Leslie Stoch is a professional electrical engineer, qualified quality management system auditor and consultant. Since 1993, he provides electrical engineering services under a PEO Certificate of Authorization, and quality management consulting services for organizations working toward ISO 9000 registration. He is a member of Professional Engineers Ontario, the American Society for Quality, the International Association of Electrical Inspectors and the Ontario Electrical League.

His electrical industry experience includes 21 years with Electrical Inspection, Ontario Hydro in electrical engineering and management positions. He is a past member of the Ontario Provincial Advisory Committee, developing recommendations on Ontario's electrical code. His clients include organizations engaged in the electrical, electronic, engineering, contracting, distribution and automotive industries. Through Dalhousie University, he provides professional development and training seminars on the electrical code and code-related subjects across Canada.

Auditor Independence

L. Stoch and Associates declares itself to be independent from Orillia Power Corporation and the work to be audited, and free of any potential threats to the auditor's independence including self-interest, self-review, advocacy, familiarity and intimidation.

Executive Overview

An audit of Orillia Power Corporation was performed on April 23 and 24, 2009 to verify the organization's extent of compliance with Ontario Regulation 22/04, to identify any gaps and to evaluate the effectiveness of procedures in place in place for compliance purposes.

The audit covered the organization's existing processes and new ones developed in response to the regulation. Except as noted, the distributor's processes are in good compliance with the regulation. No audit nonconformances were found. One opportunity for improvement and one observation are noted.

Orillia Power Corporation is an effective organization, concerned about public safety, and protecting the public from any harm that might result from its operations. The professionalism and dedication of its employees was clearly evident throughout the audit. The organization was found to be fully compliant with most of the requirements of the OR 22/04 regulation.

Nonconformances

No nonconformances were identified.

Opportunity for Improvement

The opinion of one field supervisor as to when engineering needed to be consulted on proposed field changes was found to be somewhat different from the opinions expressed by engineering staff. This issue should be reviewed to ensure better consistency.

Observation

No applications for third party attachments were submitted to the LDC nor joint use installations completed within the audit period. It was therefore not possible to confirm whether LDC's the design and CVP and requirements were met.

Management Response to ESA

The Electrical Safety Authority will ask the distributor to submit a copy of this audit report. Management will be asked to prepare a response to the audit findings. An action plan should be submitted to ESA along with the audit report.

ESA will respond directly to Orillia Power Corporation on receiving the distributor's report. An audit review meeting with ESA may take place. The audit findings listed in the report may be discussed

If any actions are required, the distributor will be asked to submit a report to ESA to provide information on progress in addressing any issues identified in the audit and action plan.

Opening Meeting

An opening meeting was held on April 23, 2009 with the following persons present:

Peter Kosik
Brenda Budd
Ritchie Udell
Tha Aung
Bob Wright
Bob Keown
David Hawkins
Glenn McCurdy
Les Stoch

Closing Meeting

A closing meeting was held on April 24, 2009 with the following persons present:

Peter Kosik
Tha Aung
Brenda Budd
Bob Wright
Ritchie Udell
Bob Keown
David Hawkins
John Mattison
Glenn McCurdy
Les Stoch

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment **up to 750 volts not part of distribution** to ensure proper operation and safety (ancillary equipment) (Maintenance and inspection schedules, logs, checklists)	Inspection and PM low voltage ancillary equipment: • Municipal street lighting installed and maintained by the LDC, inspected by ESA • Substation lighting, heating, ventilation, batteries checked during regular substation inspections • Substation batteries tested twice each year Inspection and PM records available		X		
4(4)	A maintenance and inspection program for **overhead primary and secondary distribution** lines to ensure proper operation and safety	Inspection and PM overhead systems: • Line patrols in conjunction with other programs • Annual infrared inspections and maintenance • Load-break switch maintenance – 3-year cycle • Air-break switch maintenance – 5-year cycle • Pole testing – 3-year cycle by contractor and replacement program • Tree trimming – 3-year cycle and rear lot trimming 4-year cycle • Fault indicators installed • Squirrel guards installed on transformers • Guards installed over grounding conductors • Porcelain insulation replacements during upgrades • PCB testing and elimination complete – returned transformers retested • Grounding study planned • 5-year system assessment and forecast Inspection and PM records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
4(5)	A maintenance, inspection and testing program for **underground primary and secondary distribution** lines to ensure proper operation and safety	Inspection and PM underground systems: • Direct burial cable replacements in ducts • Fault indicators installed • Padmount transformers – infrared inspections, 3-year cycle • PCB testing and elimination complete • Submersible transformers and switchgear – infrared inspections 3-year cycle • Submersible transformers inspected 2-3 times annually and underground vaults pumped out • Switchgear upgrades • Upgrading feeder cables out of substations Inspection and PM records available		X		
4(6)	A maintenance, inspection and testing program for **distribution stations** to ensure proper operation and safety	Inspection and PM substations: • Monthly substation inspections • Joint H & S inspections 3 times each year • Annual infrared inspections • Circuit-breakers inspected, tested and refurbished if necessary • Annual relay recalibration • Vegetation control by contractor • PCB testing and elimination complete • Annual oil sampling and gas analysis • RTU's maintained as necessary Inspection and PM records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
6	Distribution equipment approved when approved by **certification or field inspection;** or approved under **Rule of Distributor** • Documented outline of equipment approval process including identification of competent persons, review of test reports • List of approved major equipment up-to-date and reference to standards • Major equipment specifications approved by a competent person or P.Eng. • Approval records • Non-major equipment – Good Utility Practice • Receiving inspection	The equipment approval process is documented and it identifies persons considered competent to carry out approval responsibilities. Distribution equipment is approved under a Rule of the Distributor. As a member of USF, the LDC has access to equipment standards and certified test data on the USF web-site. Equipment specifications, identifying applicable standards have been approved by the Distribution Manager.		X		
6(1)(a)	**Specifying** equipment approved by **certification or field evaluation**	The equipment approval process is documented and only approved inventory is purchased. Non-inventory items are only purchased when approved equipment.		X		
6(1(a)	**Checking** that supplied ancillary equipment ordered is approved by **certification or field evaluation**.	Staff is aware of the need to check for evidence of equipment approval.		X		

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
6(1)(b)	**Major distribution equipment** approval under **Rule of the Distributor**: • Meets industry standards acceptable to ESA; or • Meets distributor specifications approved by a P.Eng., competent person and no undue hazard; or • Documented approval process • Supporting documentation of approvals • Certified tests reviewed by a competent person • Load-bearing equipment	The equipment approval process is documented. Major equipment is approved under a Rule of the Distributor. Certified test data is collected in hard copy and may also be available on the USF web-site. Certified test data is reviewed and signed off by a competent person. Equipment standards are available in hard copy and on the USF web-site. Equipment specifications approved by competent persons specify the standards to be met. More detailed transformer specifications are provided.		X		
6(1)(b)	**Re-Use of Major Equipment** • Documented process • Good utility practice - used major equipment approved by competent person or a P.Eng. and no undue hazard • Return to inventory – competent person confirmation of no undue hazard • Testing or repair – competent person confirms no undue hazard • Must fail safely	The re-use of equipment process is documented. Equipment returned from the field is assessed by a competent person using a Used Equipment Checklist. The checklist specifies equipment disposition and is signed by a designated competent person. Transformers returned from the field are recorded in a Distribution Transformer Re-verification form. All materials are held in a quarantine area pending disposition.		X		
6(1)(b)	**Non-major Equipment** approval under **Rule of the Distributor** (no undue hazards): • Documented approval process • Meets industry standards; or • Distributor developed specifications; or • Good utility practice – 2 years or more, documented confirmation by a competent person, no undue hazards. • GUP may include successful use in comparable systems	The equipment approval process is documented. Conformance with recognized standards is preferred by the LDC. Non-major equipment may also be approved under Good Utility Practice. A list of equipment installed on a trial basis is maintained, the equipment is inspected and a report prepared bi-annually during the 2-year trial period.		X		

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
6(1)(b)	Equipment is **specified** to meet **Rule of Distributor** standards (Purchase orders, reference to standard by model numbers, engineering specifications, technical data)	Purchase orders specify the LDC's part numbers, supplier's part numbers as well as technical data and any applicable standards. Specifications are provided to suppliers during tendering.		X		
6(1)(b)	Supplied equipment **meets Rule of Distributor** requirements • Inspection procedure • Dealing with vendor noncompliances	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition. A Receiving Checklist ensures accuracy.		X		
6(2)	**Inspection and testing** of equipment supplied based on **Rule of Distributor** requirements (Inspection and testing records)	The distributor has not developed any unique standards and relies on existing industry standards.	X			
6(2)	**Determining inspection and testing methods** for equipment supplied to distributor (Records of analysis, conclusions, manufacturers declaration, witness testing, third party or distributor testing)	The distributor has not developed any unique inspection or testing methods.	X			
6(1)(a) 6(2)	Dealing with **vendor noncompliance** (Field evaluation, rejection, communications)	Nonconforming equipment is quarantined, vendors are notified and equipment returned if necessary.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
7	Plans: • Prepared by a P.Eng.; and/or • Based on standard design drawings and specifications; and • Reviewed and approved by a P.Eng. or ESA • Plans by subdivision developers • Plans by external consultants • Records	The distributor's USF standard design drawings have been certified by ESA. Any deviations to the standards are certified by a P.Eng. Standards are available in field vehicles. Standards are documented in Pole Replacement forms and referenced as pole numbers in the plans. All overhead design is done in-house. Any proposed field changes are discussed with engineering and if agreed to, recorded in a Nonconformance Sheet. Plans are marked up and redrawn as as-build drawings. A certified electronic pole class calculator is used in overhead design.		X		
7	Approved plans or standard designs required except for: • Like-for-like construction • Emergency work • Legacy construction Design changes	Approved plans or standard designs are provided except for like-for-like, emergency and legacy construction. Underground subdivision plans may be drawn up by the developers' consulting engineers and based on the LDC's design specifications. Plans are reviewed and approved by the LDC's engineering staff. Developers' plans are certified by a P.Eng.		X		
7	Ensure third party attachments are: • Authorized; and • No adverse affect on distribution system safety • Engineering plans certified by LDC or third party P.Eng. (no gaps in certification) • Certified third party standards	Third party attachers are Bell Canada, Atria, Rogers Cable and Agilis. Observation – No third party attachment applications received within the audit period and therefore unable to assess.				

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
7	Up-to-date copies of internal specifications and identified standards available to approving P.Eng. – examples: • Electrical Safety Code • CSA Std. O/H Systems • CSA Std. U/G Systems • National Electrical Safety Code • Equipment Standards	The distributor's engineering staff has hard copy and/or electronic access to all necessary codes and standards including equipment standards.		X		
7	Ensure P.Eng. memberships valid and current	P.Eng. memberships are maintained current.		X		
7	Identify competencies of identified <u>competent persons</u> and ensure they have the required competencies (training records, position descriptions, resumes)	Qualifications of identified competent staff reviewed and confirmed.		X		
7(1)(a)	Installations based on plans by a P.Eng.: • Reviewed and approved by a P.Eng; or • Reviewed and Approved by ESA (Sample of plans)	Installations are based on standard designs reviewed and approved by ESA.		X		
7(1)(b)	Installations based on standard drawings and specifications assembled by a <u>P.Eng.</u> (Sample of drawings and specifications)	Engineering plans are normally based on standard designs assembled by competent engineering technicians and technologists.	X			
7(1)(b)	Installations based on standard drawings and specifications assembled by an <u>engineering technologist or competent person</u> (Sample of drawings and specifications)	Installations are based on standard drawings and specifications assembled by engineering technicians and technologists.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
7(2)(a) 7(2)(b)	Plans, standard design drawings and specifications **reviewed and approved** by a <u>P.Eng. or ESA</u> (Signatures, stamps)	The LDC's standard designs have been reviewed and approved by ESA. Developers' underground plans are reviewed and approved by the consulting engineer as well as the LDC's engineering staff.		X		
7(3) 7(5)	Plans, standard design drawings and specifications **certified** by a <u>P.Eng. or ESA</u> (Plans, drawings, specifications, certificates)	The LDC's standard design drawings are certified by ESA. Developers' plans are certified by a consulting engineer.		X		
7(6)	Ensure that standard design drawings, specifications and certificates are: • Recorded and tracked • As-built drawings show changes made in construction • Retained and available to ESA • Retained for minimum of one year after audit	Plans are indexed by location and project type. Mapping system is updated. Plans are maintained electronically and in project files containing: • Marked up and as-built plans • Material lists and specifications • Certificates of inspection • Correspondence • Equipment drawings • Test records		X		
8(1)	Construction verification program: • Approved by ESA • When approved • <u>Qualified persons</u> list up-to-date • Any changes approved	The CVP is approved by ESA and qualified persons list maintained up-to-date. Record of Inspection/Certificate of Approval forms for overhead line work are signed off by engineering staff or field supervision. Projects are recorded and followed up in a work management plan. Underground civil construction work is recorded and signed off by engineering staff and a final certificate of inspection is provided by the developer's P.Eng. Partial certificates are recorded for progressive work.		X		

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
8(1)	Except for like-for-like replacements, emergency and legacy work, installations based on: • Approved and certified plans before construction; or • Standard design drawings and specifications • Approved equipment • Safety standards met • Noncompliances noted in record of inspection	Approved plans are provided except for like-for-like, emergency and legacy work and approved equipment is supplied. Design changes are recorded and approved in a Nonconformance Report. Errors including any necessary corrective actions are recorded in a Noncompliance Report.		X		
8(1)	Ensure construction inspected and approved before use: • When implemented? • Monitored to cover all construction	All construction is inspected and approved before use.		X		
8(1)	Like-for-like, emergency and legacy work inspected and confirmed safe by competent person • NC's rectified • No undue hazard statement (how?) • Inspection record and certificate	Like-for-like and emergency work is inspected and confirmed safe by competent persons using a Time Sheet/Tailboard Conference Call form. Metering work by contract staff is signed off on a Record of Inspection/Certificate of Approval form.		X		
8(2)(a) 8(2)(b) 8(2)(c)	Inspection by: • P.Eng.; or • Qualified person identified in inspection verification program; or • ESA	Inspections are normally carried out by qualified staff identified in the CVP.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
8(3)	Records of inspection include: • Inspection before use of installation • Approved plan or standard design followed • Approved equipment used • Inspection date • Installation identified • Nonconformances rectified • Stamped, signed or initialed • Inspection verification program followed	Records of inspection provide all required information on what was inspected, identify the inspector and include: • Marked up and as-built plans • Record of Inspection/Certificate of Approval forms • Time Sheet/Tailboard Conference forms • Nonconformance and Noncompliance reports		X		
8(4)	Safety standards met before certification Certificates available and show: • Identify work inspected • Safety standards met • Date of certification • Stamp, signature or initials • Like-for-like and legacy construction no undue hazards	Certificates of inspection provide all necessary information on what was inspected and identify the inspector. Certificates include: • Record of Inspection/Certificate of Approval forms • Time Sheet/Tailboard Conference forms		X		
8(7)	Certificates and records of inspection available to ESA and: • Who maintains records and certificates • Covers all applicable construction • Signed and dated • Progressive inspections and sampling process certificates	Certificates and records of inspection are available in engineering project files or other departments as applicable.		X		
	Competent and qualified persons trained on CV program and process for updating	Competent and qualified staff have received CVP training and refresher training. Qualifications of competent and qualified staff reviewed and confirmed.		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
	Third party contractors trained and listed in the CVP	Work of third party contractors is inspected and recorded by the LDC's engineering staff.		X		
	Sampling program developed	No inspection sampling is done.		X		
	Process for resolving noncompliances and design changes	Noncompliances and field proposals for design changes are discussed with engineering. If agreed to, plans are marked up and eventually redrafted into as-built plans. A Nonconformance report is recorded and approved. Observation – The opinion of one field supervisor as to when engineering needed to be consulted on proposed field changes was found to be somewhat different from opinions expressed by engineering staff. Clarification should be provided to ensure better consistency.			X	
	Third party construction by contractors • Approved plan followed	Underground civil construction work is performed by the developers' contractors. Civil underground construction by contractors is inspected by the LDC's engineering staff.		X		
	Third party attachment – communications and community antenna systems: • Meets safety requirements • Noncompliances and variations resolved • Certificate of approval • Inspection by P.Eng. or person qualified in CVP • Certificate and record of inspection	Third party attachment inspections are performed by the LDC's contract P.Eng. Observation – No third party attachments were installed within the audit period and therefore unable to assess.				

NA – Not Applicable   C – Complies   NI - Needs Improvement   NC - Nonconformance

OR 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
	Public safety promotion Regular training includes safety Performance assessment includes safety Records on dealing with safety issues Training materials Safety communications Interest and input from the Board	The distributor promotes public safety in the following ways: • Children's Safety Village presentations in schools • Public safety information on distributor's web-site. • Mailing out electrical safety flyers • Emergency preparedness planning with the municipality • Participation with other safety professionals in contractor training, including ESA, MOL, EUSA, FMO • Safety materials available in the lobby • Distributor provides monthly safety reports to the Board, presented by staff members • EUSA awards – Zero Quest silver medallion • Radio electrical safety ads during Christmas holiday • Member of the CEO Health and Safety Charter organization • Electrical safety presentations to fire department • Near Miss investigations Records available		X		

NA – Not Applicable C – Complies NI - Needs Improvement NC - Nonconformance

ORILLIAPOWER

Energizing Our Community

AUDIT ACTION PLAN

ONTARIO REGULATION 22/04 – Electric Distribution Safety

Audit Date:	**April 23 & 24, 2009**
Audit Period:	**March 1, 2008 to February 28, 2009**
Report Date:	**April 25, 2009**
Auditor:	**Mr. L. Stoch, P. Eng.**

Prepared By: **Ritchie Udell**
Bob Wright

Submitted To: **Electrical Safety Authority**
155A Matheson Blvd. West, Suite 200,
Mississauga, ON
L5R 3L5

Attention: General Manager of Utility Regulation

Date: May 5, 2009

Introduction

This report has been prepared by the management of Orillia Power Distribution Corporation in order to address the findings of the O.Reg. 22/04 compliance audit, conducted by Les Stoch on April 23 & 24, 2009.

This report is identical to that issued to ESA except for the addition of management response action items which have been identified by staff as being necessary to fully address the company's activities related to fully satisfying the regulation.

Non-Conformances

No non-conformances were identified in this report.

Items Needing Improvement

The issues and action items identified below are listed in direct correlation to the items identified in Mr. Stoch's report dated April 25, 2009.

Page	Reg. Section	Identified Issue	Management Response – Action Items	Completion Date
11	8 (7)	Noncompliances and field proposals for design changes are discussed with engineering. If agreed to, plans are marked up and eventually redrafted into as-built plans. A Nonconformance report is recorded and approved. Observation – The opinion of one field supervisor as to when engineering needed to be consulted on proposed field changes was found to be somewhat different from opinions expressed by engineering staff. Clarification should be provided to ensure better consistency.	A documented meeting will be held with the engineering and distribution dept. to review proposed field design changes. Prior to any proposed field design changes being implemented, engineering will be contacted to determine if the proposed change can be made. This will ensure better consistency between the engineering and distribution departments.	May 8/09

Orillia Power Distribution Corporation

Declaration of Compliance

March 1, 2008 to February 28, 2009

Procedure for Assessment and Confirmation of Compliance with Sections 3, 9, 10, 11 and 12 of Ontario Regulation 22/04

February 7, 2007
Revision 2

Orillia Power Distribution Corporation

Procedure for Assessment and Confirmation of Compliance with Sections 3,9,10,11 and 12 of Ontario Regulation 22/04

1. Introduction

Section 14 of the Regulation requires Orillia Power Distribution Corporation (OPD) to submit to the Electrical safety Authority (ESA) an annual Declaration of Compliance with Sections 3, 9, 10, 11 and 12 of the Regulation. The Declaration must be signed by a professional engineer or a director or officer of the company. OPD's Declaration of Compliance will be signed by the President & Secretary.

The Declaration is required to be submitted annually to the ESA. The time period subject to the Declaration of Compliance will be March 1, 2008 to February 28, 2009 and must be submitted to the ESA no later than May 31, 2009. Declarations for each subsequent year are due not later than May 31 unless an extension is granted by the ESA.

This procedure presents the formal internal processes and documentation to ensure adequate compliance testing and verification to support this Declaration of Compliance. The review and validation processes may be directed and confirmed by an OPD senior manager or an independent external auditor appointed by OPD.

2. Section 3 Change of Ownership

This section identifies the requirements and obligations of OPD if there is a change to the ownership demarcation point or a transfer of ownership of a distribution system.

Any changes to the ownership demarcation point or a transfer of ownership of a distribution system shall be dealt with in accordance with Section 3 of the regulation and recorded on Form 1, as shown in Appendix A. A copy of each form shall be forwarded to the President & Secretary and the original retained, on file, within the Engineering Department. If no such forms have been received during the preceding calendar year, the President & Secretary may seek written confirmation of no such changes of ownership activities from OPD senior managers.

3. Section 9 Deviations from Required Standards

This section identifies the conditions under which OPD may put part of its distribution system into use if safety standards are not met.

All deviations from required standards shall be certified with a Certificate of Deviation Approval signed by a professional engineer, as shown below:

Certificate of Deviation Approval The installation work covered by this document meets the safety requirements of Section 4 of Regulation 22/04 with the following deviations:
________________________ ________________________ ____________
Name ____________ **Date** ____________
Signature & Professional Designation ____________

All Certificates of Deviation Approval shall be retained and recorded within the Engineering Department. All Certificates of Deviation Approval shall be noted on Form 2, as shown in Appendix B. This form shall be signed by the Distribution Superintendent and a copy forwarded to the President & Secretary at the end of each calendar year.

4. Section 10 Proximity to Distribution Lines

This section confirms the standards for the proximity of objects to energized conductors in both overhead and underground systems; it further defines the safe procedures for excavating in the vicinity of underground distribution lines.

Specific interpretations of this section are also confirmed in the following ESA Guidelines;

- ESA Guideline for Proximity to Distribution Lines – Jan. 12, 2005
- ESA Guideline for Excavating in the Vicinity of Distribution Lines – Dec. 2008

Form 3 as shown in Appendix C shall be prepared and signed by the Distribution Superintendent and a copy forwarded to the President & Secretary at the end of each calendar year, to confirm, to the best of his/her knowledge and belief, adherence to the ESA Guideline for Proximity to Distribution Lines dated Jan. 12, 2005.

Similarly, Form 4 as shown in Appendix D shall be prepared and signed by the Distribution Superintendent and a copy forwarded to the President & Secretary, at the end of each calendar year, to confirm, to the best of his/her knowledge and belief, adherence to the ESA Guideline for Excavating in the Vicinity of Distribution Lines dated Dec. 2008.

5. Section 11 Disconnection of Unused Lines

This section describes the situations under which OPD is required to disconnect and ground unused distribution lines. Further interpretation is also provided in the ESA Guideline for Disconnecting Unused Lines dated Oct. 5, 2005.

Form 5 as shown in Appendix E shall be prepared and signed by the Distribution Superintendent, at the end of each calendar year and a copy forwarded to the President & Secretary, to confirm, to the best of his/her knowledge and belief, adherence to the ESA Guideline for Disconnecting Unused Lines dated Oct. 5, 2005.

6. Section 12 Condition of Approval: Reporting of Serious Electrical Incidents

This section describes OPD's obligations for the reporting of serious electrical incidents. Further interpretation is also provided in the ESA Guideline for Reporting Serious Electrical Incidents September 15, 2008.

Form 6 as shown in Appendix F shall be prepared and signed by the Distribution Superintendent, at the end of each calendar year and a copy forwarded to the President & Secretary, to confirm, to the best of his/her knowledge and belief, adherence to the ESA Guideline for Reporting Serious Electrical Incidents September 15, 2008.

7. Annual Declaration of Compliance

Reference should be made to the ESA Guideline for Declaration of Compliance Revision 2, February 7, 2007.

Upon receipt of the above confirmations OPD's Annual Declaration of Compliance will be signed by the President & Secretary and submitted to the ESA.

The statement document will be as shown in Appendix G.

If the President & Secretary is not satisfied with the compliance of OPD, further reference will be made to the ESA Guideline for Declaration of Compliance Revision 2, dated February 7, 2007 and the statement document will be amended to indicate the instance(s) of non-compliance. The amended statement will also outline a plan to remedy the non-compliance(s) and include anticipated completion dates.

Appendix A

Orillia Power Distribution Corporation

FORM 1

Year 2009

Record of Change to the Ownership Demarcation Point or Transfer of Ownership of a Distribution System

Change/Transfer Details:

NONE

Confirmations:

I. Notification to the Electrical Safety Authority (ESA)	Yes ☐	No ☐	
II. Notification to the non-distributor that distribution system or part transferred is subject to the requirement of the Electrical Safety Code	Yes ☐	No ☐	Not Applicable ☐
Report (to be attached):			
A report identifying modifications to the distribution system or part transferred to ensure conformance with the requirements of the Electrical Safety Code has been provided to the non-distributor and to the Electrical Safety Authority	Yes ☐	No ☐	Not Applicable ☐

Signed: [signature] **Date:** May 5, 2009

Name of Position: Distribution Superintendent

Appendix B

Orillia Power Distribution Corporation

FORM 2

Certificates of Deviation Approval

Year 2009

Statement

I confirm, to the best of my knowledge and belief, OPD's adherence to Section 9 of Ontario Regulation 22/04. The following certified deviations have occurred during the last 12 months.

Location Description	Date Certified	Name of Professional Engineer
NONE		

Signed: Ritchie Udell
Distribution Superintendent

Date: May 5, 2009

Appendix C

Orillia Power Distribution Corporation

FORM 3

Statement of Adherence to the Guideline for Proximity to Distribution Lines dated Jan. 12, 2005.

Year 2009

Statement

I confirm, to the best of my/our knowledge and belief, OPD's adherence to Section 10 of Ontario Regulation 22/04 and the ESA Guideline for Proximity to Distribution Lines dated Jan. 12, 2005.

Exceptions

The following situations have occurred during the last 12 months where OPD became aware of objects in close proximity to its distribution lines. Appropriate action with the owner, the ESA and/or the Ministry of Labour is noted.

Date	Exception	Action Taken
Nov. 3, 2008	Andrew St. beside --- Mississaga St. W	Line relocation of the 4160 primary & 44,000 subtransmission to be budgeted for 2010 correction
Oct.23, 2008	Colborne St. beside --- West St. N.	Line relocation of 4160V primary to be budgeted for 2010 correction

Signed: Ritchie Udell
Distribution Superintendent

Date: May 5, 2009

Appendix D

Orillia Power Distribution Corporation.

FORM 4

Statement of Adherence to the Guideline for Excavating in the Vicinity of Distribution Lines dated December 2008

Year 2009

Statement

I confirm, to the best of my knowledge and belief, OPD's adherence to Section 10 of Ontario Regulation 22/04 and the ESA Guideline for Excavating in the Vicinity of Distribution Lines dated December 2008.

Performance Record

a.) In emergency situations OPD has made every attempt to ensure that requests for locate information is provided as soon as possible.

b.) OPD has made every reasonable effort to respond to notification requests and provide locates within 5 working days of the notification. The following table indicates any times and/or situations where this performance level was not achieved.

Date	Situation	Performance Achieved

Note: During the audit period of March 1, 2008 to February 28, 2009, 98% of all locates were achieved within 5 working days of notification.

Signed: ....
Distribution Superintendent

Date: May 5, 2009

Appendix E

Orillia Power Distribution Corporation

FORM 5

Statement of Adherence to the Guideline for Disconnecting Unused Lines

Year 2009

Statement

I confirm, to the best of my knowledge and belief, OPD's adherence to Section 11 of Ontario Regulation 22/04 and the ESA Guideline for Disconnecting Unused Lines dated Oct. 5, 2005.

Non-compliance

Section 11 (4) of the regulation allows for non-compliance with subsection (1) with a report from and a certificate signed by, a professional engineer. A sample certificate is included in Appendix A of the ESA Guideline for Disconnecting Unused Lines.

The following is a summary of any Unused Lines Certificates issued by OPD during the last 12 months:

Date	Description of Location	Name of Professional Engineer
Jan. 6, 2009	Broadview Avenue - underground primary	

Signed: ....
Distribution Superintendent

Date: May 5, 2009

Appendix F

Orillia Power Distribution Corporation

FORM 6

Statement of Adherence to the Guideline for Reporting of Serious Electrical Incidents

Year 2009

Statement

I confirm, to the best of my knowledge and belief, OPD's adherence to Section 12 of Ontario Regulation 22/04 and the ESA Guideline for Reporting Serious Electrical Incidents Rev. 2.3 dated September 15, 2008.

Incidents

Section 12 of the regulation requires the reporting of any serious electrical incident to the ESA within 48 hours after the occurrence.

The following is a summary of any Serious Electrical Incidents reported by OPD, to the ESA, during the last 12 months:

Date of Incident	Nature of Incident	Comments
	NONE	

Signed: Rutikar Vickell
Distribution Superintendent

Date: May 5, 2009

Appendix G

Orillia Power Distribution Corporation

Annual Declaration of Compliance

Year 2009

This Declaration of Compliance is submitted by Orillia Power Distribution Corporation in accordance with Ontario Regulation 22/04, Section 14. The declaration period that the Compliance covers is between March 1, 2008 to February 28, 2009.

I John Mattinson of Orillia Power Distribution Corporation state that, to the best of my knowledge and belief and having made reasonable inquiries, Orillia Power Distribution Corporation has complied with the following sections of Ontario Regulation 22/04:

1) Section 3 – Same, change of ownership;
2) Section 9 – Deviations for required standards;
3) Section 10 – Proximity to distribution lines;
4) Section 11 – Disconnection of unused lines;
5) Section 12 – Reporting of serious electrical incidents.

Orillia Power Distribution Corporation has used a methodology of review and validation of processes by senior management to assess and verify compliance. Documentation to support this review and validation process is available to the ESA, upon request.

....
Signature

....
Print Name

....
Title and/or Professional Designation

....
Date

EXHIBIT 3 - OPERATING REVENUE

Schedule No.

EXHIBIT 3 - TABLES

EXHIBIT 3 - TABLES (continued)

EXHIBIT 3 - APPENDICES

OVERVIEW / JUSTIFICATION OF FORECAST METHODOLOGY CHOSEN

The purpose of this evidence is to present the process used by OPDC to prepare the weather normalized load and customer/connection forecast used to design the proposed distribution rates. OPDC reviewed the various processes used by the 2008 and 2009 cost of service applicants and is proposing to adopt a weather normalization forecasting method similar to the one approved by the Board for 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 other 2009 cost of service applicants including London Hydro Inc., Innisfil Hydro Distribution Systems Ltd., Lakeland Power Distribution Ltd., Niagara-on-the-Lake Hydro Inc. and Thunder Bay Hydro Electricity Distribution Inc.

In summary, OPDC has used the same regression analysis methodology used by the distributors mentioned above to determine a prediction model but has altered the method for the 2009 and 2010 load forecast by including information provided in the IESO's 18-Month Outlook for June 2009 to November 2010 dated May 25, 2009 ("IESO 18-Month Outlook"). With regards to the overall process of load forecasting, it is OPDC's view that conducting a regression analysis on historical purchases to produce an equation that will predict purchases is appropriate. OPDC knows by month the exact amount of kWhs purchased from the IESO and others for use by customers of OPDC. 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 regression analysis result produces an 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 OPDC for the 2009 bridge year and 2010 test year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later on in Tab 1 Schedule 3 of this Exhibit.

During the review process of the 2009 cost of service applications, Interveners expressed concerns with the load forecasting weather process being proposed by OPDC. Interveners suggested the weather normalization should be conducted on an individual rate class basis and the regression analysis based on monthly billed kWh by rate class. In OPDC's view, conducting a regression analysis which relates the monthly billed kWh of a class 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. Using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be logical, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In OPDC'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 OPDC's view would reduce the accuracy of a regression model that is based on monthly billing data. In addition, OPDC 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.

OPDC understands that to a certain degree the process of developing a load forecast for cost of service rate application is an evolving science for electricity distributors in the province. OPDC believes it is proposing a small improvement to the method used in a number of 2009 applications by incorporating information from the IESO 18-Month Outlook. OPDC 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, OPDC submits the load forecasting methodology is reasonable at this time for the purposes of this application.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The following provides material in support of the weather normalized load forecast used by OPDC in this application. While OPDC currently does not have a process to adjust weather actual data to a weather normal basis, OPDC feels that a reasonable process to forecast energy on a weather normalized basis has been developed and used in this application as the information outlined in this Exhibit will demonstrate.

Table 3-1 below provides an overall summary of the weather normalized load and customer/connection forecast used in this application. The years 2003 to 2008 are weather actual. 2009 and 2010 are weather normalized. Total Customers are as of year-end and streetlight, sentinel lights and unmetered loads are measured as connections.

Table 3-1: Summary of Load and Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections						
2006 Board Approved	307.1			16,005		
2003 Actual	314.3			15,955		
2004 Actual	317.1	2.8	0.9%	16,099	144	0.9%
2005 Actual	323.0	5.9	1.9%	16,212	113	0.7%
2006 Actual	320.4	(2.6)	(0.8%)	16,360	148	0.9%
2007 Actual	321.1	0.7	0.2%	16,445	85	0.5%
2008 Actual	319.0	(2.1)	(0.7%)	16,570	125	0.8%
2009 Normalized Bridge	**312.5**	**(6.5)**	**(2.0%)**	**16,696**	**126**	**0.8%**
2010 Normalized Test	**311.6**	**(0.9)**	**(0.3%)**	**16,823**	**127**	**0.8%**

Table 3-2 outlines actual and forecasted billed amount and number of customers on a rate class basis. Table 3-3 indicates customer usage by rate class.

Table 3-2: Billed Energy and Number of Customers / Connections by Rate Class

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class	Total
Billed Energy (GWh)							
2006 Board Approved	107.2	44.7	151.0	2.4	0.5	1.3	307.1
2003 Actual	108.2	48.8	153.1	2.5	0.5	1.3	314.3
2004 Actual	108.4	49.8	154.6	2.5	0.5	1.3	317.1
2005 Actual	111.0	50.4	157.3	2.5	0.4	1.4	323.0
2006 Actual	108.2	49.9	158.3	2.5	0.4	1.1	320.4
2007 Actual	109.6	49.2	158.5	2.5	0.4	0.9	321.1
2008 Actual	109.8	49.3	156.1	2.5	0.4	0.9	319.0
2009 Normalized Bridge	**108.0**	**48.2**	**152.5**	**2.6**	**0.3**	**0.8**	**312.5**
2010 Normalized Test	**108.7**	**48.2**	**151.0**	**2.6**	**0.3**	**0.8**	**311.6**

Number of Customers/Connections							
2006 Board Approved	10,743	1,178	159	3,487	270	168	16,005
2003 Actual	10,595	1,278	157	3,460	278	187	15,955
2004 Actual	10,695	1,289	159	3,483	273	200	16,099
2005 Actual	10,786	1,315	155	3,490	260	206	16,212
2006 Actual	10,943	1,339	158	3,494	244	182	16,360
2007 Actual	11,061	1,344	160	3,512	212	156	16,445
2008 Actual	11,181	1,347	155	3,526	206	155	16,570
2009 Normalized Bridge	**11,295**	**1,351**	**156**	**3,541**	**200**	**153**	**16,696**
2010 Normalized Test	**11,409**	**1,355**	**157**	**3,556**	**195**	**151**	**16,823**

Table 3-3: Annual Usage per Customer/Connection by Rate Class

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class
Energy Usage per Customer/Connection (kWh per customer/connection)						
2006 Board Approved	9,976	37,984	949,614	689	1,671	7,682
2003 Actual	10,209	38,180	975,155	720	1,782	6,750
2004 Actual	10,134	38,654	972,173	723	1,684	6,681
2005 Actual	10,289	38,302	1,014,910	722	1,672	6,833
2006 Actual	9,888	37,239	1,001,619	722	1,762	6,032
2007 Actual	9,908	36,620	990,449	722	1,748	5,914
2008 Actual	9,822	36,598	1,007,301	723	1,711	5,563
2009 Normalized Bridge	**9,565**	**35,694**	**977,651**	**722**	**1,692**	**5,505**
2010 Normalized Test	**9,525**	**35,594**	**961,506**	**720**	**1,666**	**5,448**

Annual Growth Rate in Usage per Customer/Connection						
2006 Board Approved vs 2006 Actual	0.9%	2.0%	-5.2%	-4.6%	-5.2%	27.4%
2003 Actual						
2004 Actual	-0.7%	1.2%	-0.3%	0.4%	-5.5%	-1.0%
2005 Actual	1.5%	-0.9%	4.4%	-0.1%	-0.7%	2.3%
2006 Actual	-3.9%	-2.8%	-1.3%	0.0%	5.4%	-11.7%
2007 Actual	0.2%	-1.7%	-1.1%	-0.1%	-0.8%	-1.9%
2008 Actual	-0.9%	-0.1%	1.7%	0.2%	-2.1%	-5.9%
2009 Normalized Bridge	**-2.6%**	**-2.5%**	**-2.9%**	**-0.2%**	**-1.1%**	**-1.0%**
2010 Normalized Test	**-0.4%**	**-0.3%**	**-1.7%**	**-0.2%**	**-1.5%**	**-1.0%**

LOAD FORECAST AND METHODOLOGY

In the process of preparing the load forecast, OPDC reviewed the Independent Electricity System Operator's (IESO) 18-Month Outlook and is proposing to use the results of their report in the 2009 and 2010 load forecast. A copy of the IESO 18-Month Outlook is included in Appendix 3-A. In particular OPDC noted the following statements from the Executive Summary page iii:

> *"The economic downturn that began last fall has triggered a noteworthy drop in demand for electricity across North America. In Ontario, peak and energy demand have declined in recent months, in part, as wholesale industrial consumers have scaled back on consumption. Over the first three months of the year, wholesale industrial consumption of electricity dropped by approximately 20 per cent compared with the same period in 2008. Other factors affecting demand are the growth in embedded generation and the impacts of conservation. Although the North American economy is expected to recover in 2010, electricity demand is unlikely to recover within the Outlook period. Overall, electricity demand in Ontario is expected to decline by 4.0 per cent in 2009 and 0.3 per cent in 2010*
>
> *In recent months, supply and demand conditions contributed to periods of surplus baseload generation (SBG) from late March to mid‐April 2009. These periods were accompanied by record low negative prices. A confluence of factors led to these conditions:*
>
> - *Low demand due to the economic downturn, increased conservation and embedded generation, and relatively mild spring weather*
> - *High availability and output of baseload generation, including nuclear, wind and hydroelectric generation driven by spring freshet (or snow melt)*
> - *Planned transmission outages, including an outage on the New York interconnection, which significantly reduced Ontario's export capability*

In regards to the demand forecast the IESO 18-Month Outlook states on page v of the Executive Summary that *"The current recession has significantly reduced electricity demand on the system. Both energy and peak demands are tracking much lower than a year ago. Although the economy is expected to recover in 2010, electricity demand will not due to structural change in the Ontario economy, higher levels of conservation and continuing growth in embedded generation."*

The following table shows the seasonal peaks and annual energy demand over the forecast horizon from the IESO 18-Month Outlook

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2009	24,351	26,454
Winter 2009-10	22,886	24,046
Summer 2010	24,160	26,348
Year	Normal Weather Energy (TWh)	% Growth in Energy
2006 Energy	152.3	-1.9%
2007 Energy	151.6	-0.5%
2008 Energy	148.9	-1.8%
2009 Energy (Forecast)	142.9	-4.0%
2010 Energy (Forecast)	142.5	-0.3%

OPDC has included the above information in its weather normalized load forecasting process. OPDC's weather normalized load forecast is developed in a four-step process. First, a multifactor regression analysis is conducted that incorporates historical load, weather, and economic data. The regression analysis produces an equation that predicts power purchases based on the explanatory variables used in the regression analysis. The equation is used to predict 2008 power purchases under weather normal conditions.

Second, the predicted 2008 weather normal purchases are adjusted by the negative growth factors outlined in the IESO 18-Month Outlook and provided in the above table to produce a 2009 and 2010 forecast of weather normal purchases. Third, the weather normalized purchased energy forecast is adjusted by 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 that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. The forecast also recognizes load displacement generation recently announced by a customer in the OPDC service area. 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

An equation to predict 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 1996 to December 2008 to determine the monthly regression coefficients.

Data for OPDC's total system load is available as far back as January 1996. This provides 156 monthly data points which comprise 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 OPDC’s view that it is appropriate to review the impact of weather since 1996 on the energy usage and then determine the average weather conditions from January 1996 to December 2008 which would be applied in the forecasting process to determine a weather normalized forecast. However, in accordance with the filing requirement, OPDC has also provided sensitivity analysis showing the impact on the 2009 and 2010 forecast of purchases, assuming weather normal conditions, based on a 10 year average and a 20 year trend of weather data.

The multifactor regression model has determined drivers of year-over-year changes in OPDC's load growth are economic growth, weather and "calendar" factors. These factors are captured within the multifactor regression model.

Economic growth – which encompasses population trends in the OPDC service area as well as general economic conditions, is 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 two “flag” variables – one to capture the typically lower usage in the spring and fall months, and the other to capture the impact of the 2003 August blackout on energy use in that month.

The following outlines the predication model used by OPDC to predict weather normal purchases for 2008.

OPDC Monthly Predicted kWh Purchases

= Heating Degree Days * 12,931
+ Cooling Degree Days * 39,069
+ Ontario Real GDP Monthly Index * 27,062
+ Population * 933
+ Number of Peak Hours * 7,233
+ Number of Days in the Month * 522,965
+ Spring Fall Flag * (578,339)
+ Aug 03 Blackout Flag * (2,341,914)
+ Constant of (27,061,055).

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix B.

The sources of data for the various data points are as follows:

a) Environment Canada weather website for monthly heating degree day and cooling degree information. Data for local weather stations (6115820- Orillia TS, 6115811- Orillia Brain and 6117684 – Shanty Bay) was used over the time frame.
b) The 2003, 2008 and 2009 Ontario Economic Outlooks from the Ontario Ministry of Finance provided the Ontario real GDP monthly index and.
c) Population data was based on Census population data for the City of Orillia.
d) The calendar provided information related to number of days in the month and the spring/fall flag.

The prediction formula has the following statistical results listed in Table 3-4 which generally indicates the formula has a very good fit to the actual data set.

Table 3-4: Statistcial Results

Statistic	Value
R Square	96.8%
Adjusted R Square	96.6%
F Test	554.1
T-stats by Coefficient	
Intercept	(3.1)
Heating Degree Days	45.7
Cooling Degree Days	15.2
Ontario Real GDP Monthly %	1.2
Number of Days in Month	8.3
Spring Fall Flag	(4.4)
Population	2.4
Number of Peak Hours	2.3
Blackout Flag	(3.8)

The annual results of the above prediction formula compared to the actual annual purchases from 1996 to 2008 are shown in the chart below. From the graph, it can be seen that the regression model does an excellent job at predicting power consumption in Orillia.

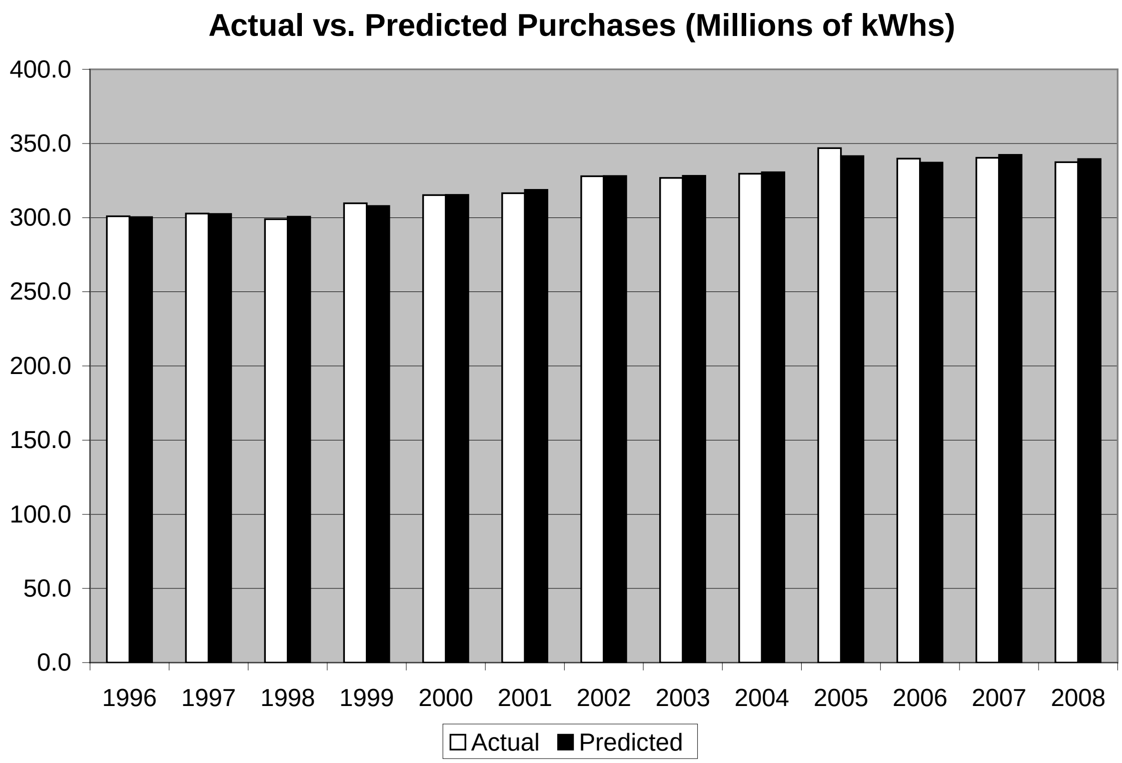

Table 3 – 5 outlines the data that supports the above chart. In addition, the predicted weather normalized total system purchases for OPDC is provided for 2008 assuming different assumptions of weather normalization. Again, this table supports the fact that the regression model does a good job of predicting purchased power within Orillia.

Table 3-5: OPDC's Total System Purchases

Year	Actual	Predicted	% Difference
Purchased Energy (GWh)			
1996	300.9	300.4	(0.2%)
1997	302.8	302.4	(0.1%)
1998	298.9	300.6	0.6%
1999	309.7	307.8	(0.6%)
2000	315.1	315.3	0.0%
2001	316.4	318.7	0.7%
2002	327.9	328.1	0.1%
2003	326.8	328.2	0.4%
2004	329.6	330.6	0.3%
2005	346.9	341.5	(1.6%)
2006	339.8	337.1	(0.8%)
2007	340.4	342.3	0.6%
2008	337.3	339.5	0.6%
2008 Weather Normal - 13 year average		**344.8**	
2008 Weather Normal - 10 year average		**345.1**	
2008 Weather Normal - 20 year trend		**344.6**	

The weather normalized amount for 2008 is determined by using 2008 dependent variables in the prediction formula on a monthly basis along with the average monthly heating degree days and cooling degree days which has occurred from January 1996 to December 2008. The 2008 weather normal 10 year average value represents the average monthly heating degree days and cooling degree days which have occurred from January 1999 to December 2008. The 2008 weather normal 20 year trend value reflects the trend in monthly heating degree days and cooling degree days which has occurred from January 1989 to December 2008.

Using the information from the IESO 18-Month Outlook the forecast of weather normal purchases for 2009 and 2010 is simply the 2008 weather normal value reduced by 4.0% in 2009 and further reduced in 2010 by 0.3%.

Table 3-6 shows the weather normal forecast of purchases for 2009 and 2010 with different assumptions in the definition of weather normal. The weather normal 13 year average has been used as the purchased forecast in this application for the purposes of determining a billed kWh load forecast which is used to design rates.

Table 3-6: 2009 and 2010 Weather Normal Forecasted Purchases

Year	Weather Normal - 13 year average	Weather Normal - 10 year average	Weather Normal - 20 year trend
Purchased Energy (GWh)			
2009 Normalized Bridge	**331.0**	**331.3**	**330.8**
2010 Normalized Test	**330.0**	**330.3**	**329.8**

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 Exhibit 8, Tab 4, Schedule 1, historically the OPDC loss factor on average has been 5.93%. Application of this average loss factor means that the total weather normalized billed energy will be 312.5 (GWh) for 2009 (i.e. 331.0/1.0593) and 311.6 (GWh) for 2010 (i.e. 330.0 /1.0593).

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 3-7.

Table 3-7: Historical Customer/Connection Data

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class	TOTAL
Number of Customers/Connections							
1996	9,903	1,298	144	3,354	288	180	15,167
1997	9,990	1,311	144	3,354	288	180	15,267
1998	10,115	1,297	144	3,354	288	180	15,378
1999	10,255	1,297	147	3,354	288	180	15,521
2000	10,349	1,294	148	3,354	288	180	15,613
2001	10,423	1,285	149	3,399	288	180	15,724
2002	10,479	1,279	149	3,443	288	179	15,817
2003	10,595	1,278	157	3,460	278	187	15,955
2004	10,695	1,289	159	3,483	273	200	16,099
2005	10,786	1,315	155	3,490	260	206	16,212
2006	10,943	1,339	158	3,494	244	182	16,360
2007	11,061	1,344	160	3,512	212	156	16,445
2008	11,181	1,347	155	3,526	206	155	16,570

From the historical customer/connection data the growth rate in customer/connection can be evaluated which is provided in Table 3-8. 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 3-8: Growth Rate in Customer/Connections

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class
Growth Rate in Customers/Connections						
1996						
1997	0.9%	1.0%	0.0%	0.0%	0.0%	0.0%
1998	1.3%	(1.1%)	0.0%	0.0%	0.0%	0.0%
1999	1.4%	0.0%	2.1%	0.0%	0.0%	0.0%
2000	0.9%	(0.2%)	0.7%	0.0%	0.0%	0.0%
2001	0.7%	(0.7%)	0.7%	1.3%	0.0%	0.0%
2002	0.5%	(0.5%)	0.0%	1.3%	0.0%	(0.6%)
2003	1.1%	(0.1%)	5.4%	0.5%	(3.5%)	4.5%
2004	0.9%	0.9%	1.3%	0.7%	(1.8%)	7.0%
2005	0.9%	2.0%	(2.5%)	0.2%	(4.8%)	3.0%
2006	1.5%	1.8%	1.9%	0.1%	(6.2%)	(11.7%)
2007	1.1%	0.4%	1.3%	0.5%	(13.1%)	(14.3%)
2008	1.1%	0.2%	(3.1%)	0.4%	(2.8%)	(0.6%)
Geometric Mean	**1.0%**	**0.3%**	**0.6%**	**0.4%**	**(2.8%)**	**(1.2%)**

The resulting geometric mean is applied to the 2008 customer/connection numbers to determine the forecast of customer/connections in 2009 and 2010. Table 3-9 outlines the forecast of customers by rate class for 2009 and 2010.

Table 3-9: Customer/Connection Forecast

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class	TOTAL
Forecast number of Customers/Connections							
2009 Normalized Bridge	**11,295**	**1,351**	**156**	**3,541**	**200**	**153**	**16,696**
2010 Normalized Test	**11,409**	**1,355**	**157**	**3,556**	**195**	**151**	**16,823**

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 3-10 provides the average annual usage per customer by rate class from 1996 to 2008 where data is available.

Table 3-10: Historical Annual Usage per Customer

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class
Annual kWh Usage Per Customer/Connection						
1996	10,757	32,852	994,931	724	1,977	6,078
1997	10,293	34,706	994,931	727	1,957	6,078
1998	9,715	36,345	994,931	728	1,942	6,078
1999	9,991	39,390	974,598	728	1,869	6,078
2000	10,024	36,969	1,015,140	734	1,897	6,078
2001	10,111	36,161	1,020,751	728	1,882	6,080
2002	10,472	38,015	1,042,059	707	1,682	6,301
2003	10,209	38,180	975,155	720	1,782	6,750
2004	10,134	38,654	972,173	723	1,684	6,681
2005	10,289	38,302	1,014,910	722	1,672	6,833
2006	9,888	37,239	1,001,619	722	1,762	6,032
2007	9,908	36,620	990,449	722	1,748	5,914
2008	9,822	36,598	1,007,301	723	1,711	5,563

As can been seen from the above table usage per customer/connection declines in the Residential and General Service Less than 50 kW classes after 2005. It is OPDC's view, that this decline is at least partially due to the CDM programs initiated in 2005.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided in Table 3-11. The geometric mean growth rate has also been shown.

Table 3-11: Growth Rate in Usage Per Customer/Connection

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class
Growth Rate in Customer/Connection						
1996						
1997	(4.3%)	5.6%	0.0%	0.5%	(1.0%)	0.0%
1998	(5.6%)	4.7%	0.0%	0.2%	(0.8%)	0.0%
1999	2.8%	8.4%	(2.0%)	(0.0%)	(3.8%)	0.0%
2000	0.3%	(6.1%)	4.2%	0.8%	1.5%	0.0%
2001	0.9%	(2.2%)	0.6%	(0.9%)	(0.8%)	0.0%
2002	3.6%	5.1%	2.1%	(2.8%)	(10.6%)	3.6%
2003	(2.5%)	0.4%	(6.4%)	1.8%	5.9%	7.1%
2004	(0.7%)	1.2%	(0.3%)	0.4%	(5.5%)	(1.0%)
2005	1.5%	(0.9%)	4.4%	(0.1%)	(0.7%)	2.3%
2006	(3.9%)	(2.8%)	(1.3%)	0.0%	5.4%	(11.7%)
2007	0.2%	(1.7%)	(1.1%)	(0.1%)	(0.8%)	(1.9%)
2008	(0.9%)	(0.1%)	1.7%	0.2%	(2.1%)	(5.9%)
Geometric Mean	**(0.3%)**	**(0.1%)**	**(0.1%)**	**(0.2%)**	**(1.3%)**	**(1.1%)**

For the forecast of usage per customer/connection the historical geometric mean was used for all rate classes and the resulting usage forecast is as follows in Table 3-12.

Table 3-12: Forecast Annual kWh Usage per Customer/Connection

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class
Forecast Annual kWh Usage per Customers/Connection						
2009 Normalized Bridge	**9,796**	**36,552**	**1,006,326**	**722**	**1,689**	**5,502**
2010 Normalized Test	**9,771**	**36,506**	**1,005,351**	**720**	**1,667**	**5,442**

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast number of customer/connection from Table 3-9 by the forecast of annual usage per customer/connection from Table 3-12. The resulting non-normalized weather billed energy forecast is shown in Table 3-13.

Table 3-13: Non-normalized Weather Billed Energy Forecast

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class	TOTAL
NON-normalized Weather Billed Energy Forecast (GWh)							
2009 (Not Normalized)	**110.6**	**49.4**	**156.9**	**2.6**	**0.3**	**0.8**	**320.7**
2010 (Not Normalized)	**111.5**	**49.5**	**157.8**	**2.6**	**0.3**	**0.8**	**322.4**

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 312.5 (GWh) for 2009 and 311.6 (GWh) for 2010.

The difference between the non-normalized and normalized forecast adjustments is 8.2 GWh in 2009 (i.e. 320.7 – 312.5) and 10.8 GWh in 2010 (i.e. 322.4 – 311.6). OPDC has one GS > 50 kW customer that will have load displacement generation beginning July 2009. As a result, the load displacement amount is expected to be 2.2 GWh in 2009 and 4.4 GWh in 2010. Increased embedded generation (i.e. load displacement generation) was one of the factors contributing to a decline in the energy forecast for 2009 and 2010 outlined in the IESO 18-Month Outlook. Since the weather normalized forecast reflects the result of the IESO 18-Month Outlook OPDC has assumed in 2009 that 2.2 GWh of load displacement generation is included in the difference between the non-normalized and normalized forecast adjustments of 8.2 GWh. OPDC has made the same assumption for 2010 that 4.4 GWh of load displacement generation is included in the 10.8 GWh difference between the non-normalized and normalized forecast.

The remaining difference of 6.0 GWh in 2009 and 6.4 GWh in 2010 is assumed to be the amount related to moving the forecast to a weather normal basis. This difference will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for OPDC 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 in Table 3-14. As a result, the difference of 6.0 GWh in 2009 and 6.4 GWh in 2010 has been assigned on a prorate basis to each rate classes based on the level of weather sensitivity indicated in the table.

Table 3-14: Weather Sensitivity by Rate Class

Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class
Weather Sensitivity					
100%	**100%**	**60%**	**0%**	**0%**	**0%**

Table 3-15 demonstrates how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast. In addition, the impact of load displacement generation is also included to show how the weather normalized billed energy forecast has been determined.

Table 3-15: Alignment of Non-normal to Weather Normal Forecast

Year	Residential Class	General Service Less than 50 kW Class	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	Unmetered Scattered Load Class	TOTAL
Non-normalized Weather Billed Energy Forecast (GWh)							
2009 NON-Normalized Bridge	**110.6**	**49.4**	**156.9**	**2.6**	**0.3**	**0.8**	**320.7**
2010 NON-Normalized Test	**111.5**	**49.5**	**157.8**	**2.6**	**0.3**	**0.8**	**322.4**
Adjustment to Billed Energy Forecast for Load Displacement Generation							
2009 Normalized Bridge	**0.0**	**0.0**	**(2.2)**	**0.0**	**0.0**	**0.0**	**(2.2)**
2010 Normalized Test	**0.0**	**0.0**	**(4.4)**	**0.0**	**0.0**	**0.0**	**(4.4)**
Adjustment for Weather (GWh)							
2009 Normalized Bridge	**(2.6)**	**(1.2)**	**(2.2)**	**0.0**	**0.0**	**0.0**	**(6.0)**
2010 Normalized Test	**(2.8)**	**(1.2)**	**(2.4)**	**0.0**	**0.0**	**0.0**	**(6.4)**
Weather Normalized Billed Energy Forecast (GWh)							
2009 Normalized Bridge	**108.0**	**48.2**	**152.5**	**2.6**	**0.3**	**0.8**	**312.5**
2010 Normalized Test	**108.7**	**48.2**	**151.0**	**2.6**	**0.3**	**0.8**	**311.6**

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on per kW basis. These include General Service > 50 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. Table 3-16 outlines the annual demand units by applicable rate class.

Table 3-16: Historical Annual kW per Applicable Rate Class

Year	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	TOTAL
Billed Annual kW				
1996	380,570	6,750	1,582	388,902
1997	376,940	6,781	1,566	385,287
1998	384,000	6,792	1,554	392,346
1999	389,697	6,783	1,495	397,975
2000	397,889	6,846	1,517	406,252
2001	410,390	6,897	1,506	418,793
2002	400,427	6,352	1,222	408,001
2003	424,930	6,981	1,376	433,287
2004	391,840	7,006	1,273	400,119
2005	405,678	7,036	1,208	413,922
2006	407,943	7,045	1,195	416,183
2007	409,427	7,076	1,029	417,532
2008	396,778	7,084	979	404,841

The following information in Table 3-17 is the historical ratio of kW/kWh as well as the average ratio.

Table 3-17: Historical kW/KWh Ratio per Applicable Rate Class

Year	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class
Ratio of kW to kWh			
1996	0.2656%	0.2781%	0.2778%
1997	0.2631%	0.2781%	0.2778%
1998	0.2680%	0.2781%	0.2778%
1999	0.2720%	0.2778%	0.2777%
2000	0.2648%	0.2780%	0.2777%
2001	0.2698%	0.2787%	0.2779%
2002	0.2579%	0.2608%	0.2522%
2003	0.2776%	0.2802%	0.2778%
2004	0.2535%	0.2784%	0.2770%
2005	0.2579%	0.2792%	0.2779%
2006	0.2578%	0.2792%	0.2779%
2007	0.2584%	0.2792%	0.2776%
2008	0.2541%	0.2779%	0.2778%
Average	**0.2631%**	**0.2772%**	**0.2758%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3-15 to provide the forecast of kW by rate class as shown below in Table 3-18. The following outlines the forecast of kW for the applicable rate classes.

Table 3-18: kW Forecast by Applicable Rate Class

Year	General Service Greater than or Equal to 50 kW Class	Streetlight Class	Sentinel Lighting Class	TOTAL
Predicted Billed kW				
2009 Normalized Bridge	**401,289**	**7,082**	**933**	**409,304**
2010 Normalized Test	**397,192**	**7,098**	**896**	**405,185**

Table 3-19 on the next page provides a summary of the billing determinants by rate class that have been used to develop the proposed rates.

Table 3-19: Summary of Forecast

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Weather Normal Bridge	2010 Weather Normal Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases	329,583,057	339,836,662	340,350,915	337,342,212		
Predicted kWh Purchases before load displ	330,620,505	337,109,848	342,278,129	339,502,489	331,040,422	**330,047,301**
Adjustments for Load Displacement		0	0	0	0	**0**
Revised Predicted kWh Purchases after loa	330,620,505	337,109,848	342,278,129	339,502,489	331,040,422	**330,047,301**
% Difference between actual and predict	**0.3%**	**(0.8%)**	**0.6%**	**0.6%**		
BILLING DETERMINANTS BY CLASS						
RESIDENTIAL CLASS						
Customers	10,743	10,943	11,061	11,181	11,295	**11,409**
kWh	107,176,659	108,206,276	109,590,116	109,814,584	108,037,105	**108,676,163**
GENERAL SERVICE LESS THAN 50 KW CLASS						
Customers	1,178	1,339	1,344	1,347	1,351	**1,355**
kWh	44,745,529	49,863,299	49,217,302	49,297,751	48,222,530	**48,230,452**
GENERAL SERVICE GREATER THAN OR EQUAL TO 50 KW CLASS						
Customers	159	158	160	155	156	**157**
kW	376,542	407,943	409,427	396,778	401,289	**397,192**
kWh	150,988,670	158,255,829	158,471,800	156,131,676	152,513,510	**150,956,406**
STREETLIGHT CLASS						
Connections	3,487	3,494	3,512	3,526	3,541	**3,556**
kW	6,814	7,045	7,076	7,084	7,082	**7,098**
kWh	2,402,165	2,523,604	2,534,043	2,549,242	2,554,940	**2,560,651**
SENTINEL LIGHTING CLASS						
Connections	270	244	212	206	200	**195**
kW	1,260	1,195	1,029	979	933	**896**
kWh	451,084	430,027	370,616	352,408	338,308	**324,773**
Unmetered Loads						
Connections	168	182	156	155	153	**151**
kWh	1,290,526	1,097,760	922,608	862,308	842,265	**822,688**
Total						
Customer/Connections	**16,005**	**16,360**	**16,445**	**16,570**	**16,696**	**16,823**
kWh	**307,054,633**	**320,376,795**	**321,106,485**	**319,007,969**	**312,508,658**	**311,571,133**
kW from applicable classes	**384,616**	**416,183**	**417,532**	**404,841**	**409,304**	**405,186**

TABLES FOR DISTRIBUTION AND OTHER REVENUES WITH VARIANCES

Exhibit 3, Tab 2, Schedule 1 summarizes Distribution and Other Revenues for 2006 EDR through to 2010 Test with variances. Commentary on the variances follows in Exhibit 3 Tab 3 Schedules 2 & 3.

Table 3-20: DISTRIBUTION REVENUES - Summary From 2006 EDR To 2010 Test and Variance Analysis

Materiality Threshold For Variance Explanation	50,000

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
DISTRIBUTION REVENUES											
Residential	2,994,450	3,142,306	3,089,184	3,156,469	3,113,565	3,628,315	**147,856**	**(53,122)**	**67,285**	(42,904)	**514,750**
GS <50 kW	1,037,021	1,212,089	1,166,698	1,185,658	1,159,384	1,341,449	**175,068**	(45,391)	18,960	(26,274)	**182,065**
GS>=50 kW	1,663,370	1,829,724	1,776,388	1,736,701	1,740,315	1,929,795	**166,354**	**(53,336)**	(39,687)	3,614	**189,480**
Street Light	67,609	76,152	66,266	69,778	70,021	179,358	8,543	(9,886)	3,512	243	**109,337**
Sentinel	20,625	19,553	16,737	15,702	15,429	17,262	(1,072)	(2,816)	(1,035)	(273)	1,833
Unmetered Scattered Load	50,927	63,629	42,128	41,507	39,856	20,721	12,702	(21,501)	(621)	(1,651)	(19,135)
Total Distribution Revenues	**5,834,002**	**6,343,453**	**6,157,401**	**6,205,815**	**6,138,570**	**7,116,900**	**509,451**	**(186,052)**	**48,414**	**(67,245)**	**978,330**

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
RECONCILIATION TO LAST BOARD APPROVED YEAR, AUDITED FINANCIAL STATEMENTS, BRIDGE AND TEST YEARS						
Dist. Rev. per financial statements	**5,834,000**	**6,387,000**	**6,201,000**	**6,241,000**	**6,178,000**	**6,725,000**
Revenues per table above (rounded)	5,834,000	6,343,000	6,157,000	6,206,000	6,139,000	7,117,000
Reconciling Items						
SSS Admin and other 4080		44,000	44,000	35,000	39,000	46,000
Dist. Rev. per financial statements	**5,834,000**	**6,387,000**	**6,201,000**	**6,241,000**	**6,178,000**	**6,725,000**
Difference should be NIL	-	-	-	-	-	-

Table 3-21: Other Revenues and Interest - SUMMARY - From 2006 EDR To 2010 Test

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
SUMMARY OF OTHER REVENUES AND INTEREST INCOME											
Revenues from services - Distribution	61,100	65,600	68,800	56,800	61,300	68,300	4,500	3,200	(12,000)	4,500	7,000
Other Operating Revenues	366,500	474,700	497,200	580,700	480,000	505,000	**108,200**	22,500	**83,500**	**(100,700)**	25,000
Other Income / Deductions	(122,800)	1,742,200	(8,400)	(12,700)	(40,000)	(40,000)	**1,865,000**	**(1,750,600)**	(4,300)	(27,300)	-
Interest Income	134,800	242,300	217,800	143,000	5,000	8,000	**107,500**	(24,500)	**(74,800)**	**(138,000)**	3,000
Other Revenues and Interest - LDC	**439,600**	**2,524,800**	**775,400**	**767,800**	**506,300**	**541,300**	**2,085,200**	**(1,749,400)**	**(7,600)**	**(261,500)**	**35,000**

RECONCILIATION TO LAST BOARD APPROVED YEAR, AUDITED FINANCIAL STATEMENTS, BRIDGE AND TEST YEARS						
Other revenues per financial statements		**2,261,000**	**498,000**	**600,000**	**460,000**	**485,000**
Interest income per financial statements		**198,000**	**208,000**	**131,000**	**5,000**	**8,000**
Total per financial statements		**2,459,000**	**706,000**	**731,000**	**465,000**	**493,000**
Revenues per table above (rounded)		2,525,000	775,000	768,000	506,000	541,000
Reconciling Items						
Non LDC Revenues 4375, 4380, 4385		45,000	9,000	32,000	20,000	20,000
Revenues from services - Distribution		(66,000)	(69,000)	(57,000)	(61,000)	(68,000)
Regulatory asset carrying charges		(45,000)	(9,000)	(12,000)		
Other revenues / interest per fs		**2,459,000**	**706,000**	**731,000**	**465,000**	**493,000**
Difference should be NIL		**-**	**-**	**-**	**-**	**-**

Table 3-22: Revenues From Services - Distribution - From 2006 EDR To 2010 Test With Variances

Materiality Threshold For Variance Explanation	50,000

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
REVENUES FROM SERVICES - DISTRIBUTION											
4080-Distribution Services Revenue - SSS	44,000	43,500	43,500	35,100	32,900	33,400	(500)	-	(8,400)	(2,200)	500
4080-Distribution Services Revenue - Stand	-	-	-	-	6,400	12,900	-	-	-	6,400	6,500
4082-Retail Services Revenues	17,000	20,400	23,600	20,900	21,000	21,000	3,400	3,200	(2,700)	100	-
4084-Service Transaction Requests	100	1,700	1,700	800	1,000	1,000	1,600	-	(900)	200	-
Total Revenues from Services - Dist	**61,100**	**65,600**	**68,800**	**56,800**	**61,300**	**68,300**	**4,500**	**3,200**	**(12,000)**	**4,500**	**7,000**
Variance							**[(2) - (1)]**	**[(3) - (2)]**	**[(4) - (3)]**	**[(5) - (4)]**	**[(6) - (5)]**

Table 3-23: Other Operating Revenues - From 2006 EDR To 2010 Test With Variances

Materiality Threshold For Variance Explanation	50,000

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
OTHER OPERATING REVENUES											
4205-Interdepartmental Rents	28,800	34,200	35,500	36,800	36,000	37,000	5,400	1,300	1,300	(800)	1,000
4220-Other Electric Revenues	69,900	99,200	87,200	171,800	80,000	90,000	29,300	(12,000)	**84,600**	**(91,800)**	10,000
4225-Late Payment Charges	65,100	100,900	59,200	46,300	50,000	60,000	35,800	(41,700)	(12,900)	3,700	10,000
4235-Miscellaneous Service Revenues	202,700	240,400	315,300	325,800	314,000	318,000	37,700	**74,900**	10,500	(11,800)	4,000
Total Other Operating Revenues	**366,500**	**474,700**	**497,200**	**580,700**	**480,000**	**505,000**	**108,200**	**22,500**	**83,500**	**(100,700)**	**25,000**

Table 3-24: Other Income / Deductions - From 2006 EDR To 2010 Test With Variances

Materiality Threshold For Variance Explanation **50,000**

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
OTHER INCOME / DEDUCTIONS											
4325-Revenues from Merchandise, Jobbing	800	33,400	50,900	13,600	30,000	30,000	32,600	17,500	(37,300)	16,400	-
4355-Gain on Disposition of Utility and Othe	300	1,800	10,100	800	-	-	1,500	8,300	(9,300)	(800)	-
4360-Loss on Disposition of Utility and Othe	(123,900)	(71,800)	(69,400)	(27,100)	(70,000)	(70,000)	**52,100**	2,400	42,300	(42,900)	-
4375-Revenues from Non-Utility Operations	-	-	112,900	86,300	50,000	77,000	-	**112,900**	(26,600)	(36,300)	27,000
4380-Expenses of Non-Utility Operations	-	-	(122,700)	(70,300)	(50,000)	(77,000)	-	**(122,700)**	**52,400**	20,300	(27,000)
4385-Non-Utility Rental Income	65,500	44,600	19,000	15,800	20,000	20,000	(20,900)	(25,600)	(3,200)	4,200	-
4390-Miscellaneous Non-Operating Income	-	1,778,800	-	-	-	-	**1,778,800**	**(1,778,800)**	-	-	-
Total Other Income / Deductions	**(57,300)**	**1,786,800**	**800**	**19,100**	**(20,000)**	**(20,000)**	**1,844,100**	**(1,786,000)**	**18,300**	**(39,100)**	**-**
Non LDC Revenues 4375, 4380, 4385	65,500	44,600	9,200	31,800	20,000	20,000	(20,900)	(35,400)	22,600	(11,800)	-
Other Income / Deductions - LDC	**(122,800)**	**1,742,200**	**(8,400)**	**(12,700)**	**(40,000)**	**(40,000)**	**1,865,000**	**(1,750,600)**	**(4,300)**	**(27,300)**	**-**

Table 3-25: Interest Income - From 2006 EDR To 2010 Test With Variances

Materiality Threshold For Variance Explanation **50,000**

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
INTEREST INCOME											
4405-Interest and Dividend Income	134,800	242,300	217,800	143,000	5,000	8,000	**107,500**	(24,500)	**(74,800)**	**(138,000)**	3,000
Total Interest Income	**134,800**	**242,300**	**217,800**	**143,000**	**5,000**	**8,000**	**107,500**	**(24,500)**	**(74,800)**	**(138,000)**	**3,000**

OVERVIEW OF OPERATING AND OTHER REVENUES:

The previous tab, Exhibit 3 Tab1 outlines OPDC's methodology for forecasting weather normalized load and other billing determinants for the 2009 Bridge Year and the 2010 Test Year. The forecasted billing determinants were used in determining the revenues under existing rates and proposed rates assuming rates in effect for an entire calendar year.

Exhibit 3, Tab 2 summarizes Distribution and Other Revenues in table format for 2006 EDR through to 2010 Test with the associated year over year variances. This Tab also provides a detailed variance analysis by rate class of the operating revenue components and a detailed variance analysis of all significant other revenues as well. Commentary on variances over the materiality threshold of $50,000 can be found in Exhibit 3 Tab 3 Schedules 2 & 3 for 2006 EDR Board Approved, 2006 Actual, 2007 Actual, 2008 Actual the 2009 Bridge Year and the 2010 Test Year.

Revenues have been calculated using the appropriate OEB approved Schedule of Rates and Charges for each year as applicable. Distribution revenue does not include revenue from commodity sales. It also does not include revenue from other deferral and variance account riders such as the smart meter funding adder, the low voltage recovery adder or the repayment of deferral and variance accounts. Distribution revenues are net of applicable transformer allowance.

Other revenues include late payment charges, miscellaneous service revenues, interest income, collection charges, rental income and retail services revenues among other things.

A summary of operating and other revenues has been presented in Table 3-26.

A summary of dollars billed per kWh / kW (billing determinant) for core distribution revenues is presented in Table 3-27.

Table 3-26: Summary of DISTRIBUTION and Other Revenues - From 2006 EDR To 2010 Test

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
DISTRIBUTION REVENUES						
Residential	2,994,450	3,142,306	3,089,184	3,156,469	3,113,565	3,628,315
GS <50 kW	1,037,021	1,212,089	1,166,698	1,185,658	1,159,384	1,341,449
GS>=50 kW	1,663,370	1,829,724	1,776,388	1,736,701	1,740,315	1,929,795
Street Light	67,609	76,152	66,266	69,778	70,021	179,358
Sentinel	20,625	19,553	16,737	15,702	15,429	17,262
Unmetered Scattered Load	50,927	63,629	42,128	41,507	39,856	20,721
Total Distribution Revenues (1)	**5,834,002**	**6,343,453**	**6,157,401**	**6,205,815**	**6,138,570**	**7,116,900**
Total Distribution Revenues (00's)	**5,834,000**	**6,343,500**	**6,157,400**	**6,205,800**	**6,138,600**	**7,116,900**
SUMMARY OF OTHER REVENUES AND INTEREST INCOME						
Revenues from services - Distribution	61,100	65,600	68,800	56,800	61,300	68,300
Other Operating Revenues	366,500	474,700	497,200	580,700	480,000	505,000
Other Income / Deductions	(122,800)	1,742,200	(8,400)	(12,700)	(40,000)	(40,000)
Interest Income	134,800	242,300	217,800	143,000	5,000	8,000
Other Revenues and Interest - LDC	**439,600**	**2,524,800**	**775,400**	**767,800**	**506,300**	**541,300**
Total Revenues	**6,273,600**	**8,868,300**	**6,932,800**	**6,973,600**	**6,644,900**	**7,658,200**
Less PMOEV amount (2)	-	1,779,000	-	-	-	-
Adjusted Total Revenues	**6,713,200**	**7,089,300**	**6,932,800**	**6,973,600**	**6,644,900**	**7,658,200**
% Variance from 2006 EDR - Board Approved		6%	3%	4%	-1%	14%
% Variance from prior year			-2%	1%	-5%	15%

(1) Revenues are net of transformer allowances

(2) PMOEV relates to the years 2001 and 2002 and is explained further in Ex 3 Tab 3 Schedule 3

Table 3-27: Summary of $ of Revenue per kWh / kW - From 2006 EDR To 2010 Test

Description		2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
DISTRIBUTION REVENUES - BILLING DETERMINANTS							
Residential	kWh	107,176,659	108,206,276	109,590,116	109,814,584	108,037,105	108,676,163
GS <50 kW	kWh	44,745,529	49,863,299	49,217,302	49,297,751	48,222,530	48,230,452
GS>=50 kW	kW	376,541	407,943	409,427	396,778	401,289	397,192
Street Light	kW	6,814	7,045	7,076	7,084	7,082	7,098
Sentinel	kW	1,260	1,195	1,029	979	933	896
Unmetered Scattered Load	kWh	1,290,526	1,097,760	922,608	862,308	842,265	822,688
DISTRIBUTION REVENUES - $$ PER BILLING DETERMINANT							
Residential	kWh	0.0279	0.0290	0.0282	0.0287	0.0288	0.0334
GS <50 kW	kWh	0.0232	0.0243	0.0237	0.0241	0.0240	0.0278
GS>=50 kW	kW	4.4175	4.4852	4.3387	4.3770	4.3368	4.8586
Street Light	kW	9.9221	10.8094	9.3649	9.8501	9.8872	25.2688
Sentinel	kW	16.3690	16.3623	16.2653	16.0388	16.5370	19.2656
Unmetered Scattered Load	kWh	0.0395	0.0580	0.0457	0.0481	0.0473	0.0252
DISTRIBUTION REVENUES - $$ PER BILLING DETERMINANT - PERCENTAGE CHANGE YEAR OVER YEAR							
Residential	kWh		4%	-3%	2%	0%	16%
GS <50 kW	kWh		5%	-2%	1%	0%	16%
GS>=50 kW	kW		2%	-3%	1%	-1%	12%
Street Light	kW		9%	-13%	5%	0%	156%
Sentinel	kW		0%	-1%	-1%	3%	17%
Unmetered Scattered Load	kWh		47%	-21%	5%	-2%	-47%

VARIANCE ANALYSIS ON OPERATING REVENUE:

The tables in Exhibit 3 Tab 2 present core distribution revenues by class for 2006 EDR, 2006 Actual through to 2010 Test. Distribution revenue year over year variances greater than $50,000 are explained in this section. The excerpt from Table 3-20 is shown below and indicates the variances that will be explained in this section.

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
DISTRIBUTION REVENUES						
Residential	2,994,450	3,142,306	3,089,184	3,156,469	3,113,565	3,628,315
GS <50 kW	1,037,021	1,212,089	1,166,698	1,185,658	1,159,384	1,341,449
GS>=50 kW	1,663,370	1,829,724	1,776,388	1,736,701	1,740,315	1,929,795
Street Light	67,609	76,152	66,266	69,778	70,021	179,358
Sentinel	20,625	19,553	16,737	15,702	15,429	17,262
Unmetered Scattered Load	50,927	63,629	42,128	41,507	39,856	20,721
Total Distribution Revenues	**5,834,002**	**6,343,453**	**6,157,401**	**6,205,815**	**6,138,570**	**7,116,900**
Percentage change		**8.7%**	**-2.9%**	**0.8%**	**-1.1%**	**15.9%**

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
Residential		**147,856**	**(53,122)**	**67,285**	(42,904)	**514,750**
GS <50 kW		**175,068**	(45,391)	18,960	(26,274)	**182,065**
GS>=50 kW		**166,354**	**(53,336)**	(39,687)	3,614	**189,480**
Street Light		8,543	(9,886)	3,512	243	**109,337**
Sentinel		(1,072)	(2,816)	(1,035)	(273)	1,833
Unmetered Scattered Load		12,702	(21,501)	(621)	(1,651)	(19,135)
Total Distribution Revenues		**509,451**	**(186,052)**	**48,414**	**(67,245)**	**978,330**

Comparison of 2006 Actual to 2006 EDR (Board Approved):

2006 core actual revenues were 8.7% higher than Board approved revenues. 2006 Board approved rates were implemented on May 1, 2006 and the 2006 Board approved revenues reflect the application of those rates for a full 12 month time frame. Actual calendar year 2006 revenues presented above reflect revenues at higher 2005 rates for the first 4 months of 2006 and 2006 rates for the remaining 8 months of 2006.

2006 rates decreased by an average of 9.1% and revenues from those reduced rates are not reflected in the first 4 months actual results. As a result, 2006 actual average $'s per billing determinant were higher by an average of 3.8% than average $'s per billing determinant from the 2006 Board approved rates. In addition, 2006 actual kWh/kW consumption was higher by an average of 4.9% than billing determinants used in calculating the 2006 Board approved rates. The revenue variance of 8.7% is attributable to both the implementation date of the 2006 Board approved rates and higher 2006 actual billing determinants.

Comparison of 2007 Actual to 2006 Actual and 2006 Board Approved:
2007 actual revenues were 2.9% lower than 2006 actual and 5.5% higher than 2006 Board approved revenues. 2007 revenues are based on 2006 Board approved rates for the full calendar year, plus the mechanistic rate adjustment of 0.9% effective May 1, 2007.

The flow through effect in 2007 of the May 1, 2006 rate decrease is the primary cause of the 2.9% decrease in revenues from 2006 to 2007. The increase of 5.5% from 2006 Board approved to 2007 actual reflects the 0.9% mechanistic rate adjustment for 2007 plus the effect of higher 2007 actual kWh/kW consumption as compared to billing determinants used in calculating the 2006 Board approved rates as mentioned above.

Comparison of 2008 Actual to 2007 Actual and 2006 Board Approved:
2008 actual revenues were 0.8% higher than 2007 actual and 6.4% higher than 2006 Board approved revenues. 2008 revenues are based on 2007 Board approved rates for the full calendar year, plus a mechanistic rate adjustment of -0.1% effective May 1, 2008.

The flow through effect in 2008 of the May 1, 2007 rate increase is the primary cause of the 0.8% increase in revenues from 2007 to 2008. The increase of 6.4% from 2006 Board approved to 2008 actual reflects the mechanistic rate adjustments for 2007 and 2008 plus the effect of higher 2008 actual kWh/kW consumption as compared to billing determinants used in calculating the 2006 Board approved rates as mentioned above.

Comparison of 2009 Bridge to 2008 Actual and 2006 Board Approved:

2009 Bridge Year revenues are 1.1% lower than 2008 actual and 5.2% higher than 2006 Board approved revenues. 2009 revenues are based on 2008 Board approved rates for the full calendar year, plus a mechanistic rate adjustment of 0.2% effective May 1, 2009.

The decrease of 1.1% in revenues from 2008 to 2009 is comprised of the flow through effect in 2009 of the May 1, 2008 rate decrease and a forecasted 1% decrease in volumes. The increase of 5.2% from 2006 Board approved to 2009 reflects the mechanistic rate adjustments for 2008 and 2009 plus the effect of higher 2009 forecasted kWh/kW consumption as compared to billing determinants used in calculating the 2006 Board approved rates as mentioned above.

Comparison of 2010 Test Year to 2009 Bridge and 2006 Board Approved:

The 2010 Test Year revenues are based on the proposed rates and forecast to be 15.9% higher than 2009 Bridge Year and 22% higher than 2006 Board Approved revenues. Revenues by rate class reflect the impacts of proposed cost allocation adjustments to the street light class to bring revenue to cost ratios in line with Board recommended ranges. The increase of 22% from 2006 Board approved amounts is comprised of rate adjustments in 2007, 2008, 2009 and 2010 totaling 16.9% over the period plus the effect of higher 2010 forecasted kWh/kW consumption as compared to billing determinants used in calculating the 2006 Board approved rates as mentioned above.

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE:

Materiality Threshold:

The tables in Exhibit 3 Tab 2 present other revenues by category for 2006 EDR, 2006 Actual through to 2010 Test. Other revenue year over year variances greater than $50,000 are explained in this section. Excerpts from the tables are shown before the explanation.

Explanation of Variance _ Other Electric Revenues:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
OTHER OPERATING REVENUES						
4220-Other Electric Revenues	69,900	99,200	87,200	171,800	80,000	90,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
4220-Other Electric Revenues		29,300	(12,000)	**84,600**	**(91,800)**	10,000

OPDC experienced unusually high levels of sundry accounts receivable work in 2008. The increase of $84,600 represents markup on our billable work charged to other electric revenues associated with the high level of activity. We are expecting a normal level of activity in 2009 causing the variance to go the other way by a similar amount.

Explanation of Variance _ Miscellaneous Service Revenues:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
OTHER OPERATING REVENUES						
4235-Miscellaneous Service Revenues	202,700	240,400	315,300	325,800	314,000	318,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
4235-Miscellaneous Service Revenues		37,700	**74,900**	10,500	(11,800)	4,000

OPDC revised and streamlined collections processes in the fall of 2006 resulting in more revenues on an ongoing basis from unpaid bill reminder notices delivered to the customers home and reconnection charges. These notices are a reminder to customers that their bill remains unpaid past the due date and that disconnect is the next step should their bill remain unpaid. The customer is charged for this notice as per our approved rate order. Approximately $81,000 was generated from these charges offset slightly by reductions in other charges accounting for the variance of $74,900.

Explanation of Variance _ Loss on Disposition:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
OTHER INCOME / DEDUCTIONS						
4360-Loss on Disposition of Utility and Othe	(123,900)	(71,800)	(69,400)	(27,100)	(70,000)	(70,000)

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
4360-Loss on Disposition of Utility and Other Property		**52,100**	2,400	42,300	(42,900)	-

The 2006 EDR (OEB approved) amount included a one-time $60,000 write-off of obsolete inventory, which more than accounts for the variance to 2006 Actual. The 2006 Actual figure is in line with the normal annual expenditures for this account.

Explanation of Variance _ Revenues from Non-Utility Operations:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
OTHER INCOME / DEDUCTIONS						
4375-Revenues from Non-Utility Operations	-	-	112,900	86,300	50,000	77,000
4380-Expenses of Non-Utility Operations	-	-	(122,700)	(70,300)	(50,000)	(77,000)

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
4375-Revenues from Non-Utility Operations		-	**112,900**	(26,600)	(36,300)	27,000
4380-Expenses of Non-Utility Operations		-	**(122,700)**	**52,400**	20,300	(27,000)

The Ontario Power Authority ("OPA") began funding conservation and demand ("CDM") programs in 2007 for delivery through electricity distributors. OPDC participated in Summer Savings, Refrigerator Roundup and Electricity Retrofit Incentive Programs in 2007. OPA-funded CDM programs are not regulated by the OEB and therefore are classified as non-distribution activities. Account 4375, Revenues from Non-Utility Operations, and account 4380, Expenses from Non-Utility Operations, track revenues and expenses relating to these programs. OPDC continues to participate in these programs, adding the Direct Install Incentive for small commercial customers in 2008. Revenues and expenses were lower in 2008 mainly due to the lower cost of the 2008 Summer Sweepstakes Contest which replaced the 2007 Summer Savings Program under which OPDC paid out incentives of $36,000 to our customers.

Explanation of Variance _ Miscellaneous Non-Operating Income:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
OTHER INCOME / DEDUCTIONS						
4390-Miscellaneous Non-Operating Income	-	1,778,800	-	-	-	-

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
4390-Miscellaneous Non-Operating Income		**1,778,800**	**(1,778,800)**	-	-	-

In 2006, in conjunction with the OEB review and approval of OPDC rates, OPDC recorded the recovery of the pre market opening energy variance (PMOEV) in other miscellaneous non-operating income. The note in italics below is an excerpt from Note 5 of OPDC's 2006 audited financial statements:

*"**5. Regulatory assets and liabilities** (Continued)*
In a letter dated December 19, 2003, the Minister of Energy granted approval for distributors to make application to the OEB with regard to recovery through rates of distribution regulatory assets related to market opening whose previous inclusion in rates was delayed by the Electricity Pricing, Conservation and Supply Act, 2002. These distribution regulatory assets were expected to be recovered in rates over a four year period, commencing April 1, 2004. All amounts to be recovered including the pre-market opening energy variance and qualifying market transition costs, however, were to be subject to a future OEB review. The company applied for and received final OEB approval to recover market opening regulatory assets as part of its May 1, 2006 rate application.

Pre-market opening energy variance (PMOEV)
The PMOEV account was established for the purpose of recording the estimated difference between the company's purchased cost of power based on time-of-use pricing and amounts billed to non-time-of-use customers charged at an average rate for the same period starting January 1, 2001 and ending May 1, 2002, the date of market opening. Due to uncertainty surrounding the approval process in 2002 the company recorded an offsetting liability instead of adjusting income. The company has now recorded the pre-market opening energy variance and related accrued interest of $1,779 as other revenue for 2006 in conjunction with receiving OEB approval to recover these costs. Amounts recovered from customers to date through rates for pre-market opening energy variance for 2006 are $1,630 (2005 - $963). "

Explanation of Variance _ Interest and Dividend Income:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
INTEREST INCOME						
4405-Interest and Dividend Income	134,800	242,300	217,800	143,000	5,000	8,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
4405-Interest and Dividend Income		**107,500**	(24,500)	**(74,800)**	**(138,000)**	3,000

Table 3-28 is an interest estimation calculation intended to show the reasonableness of the interest income account and explain the variances indicated above. It is intended to illustrate and explain the significant drop in interest income over the period from 2004 through 2010.

Interest and dividend income includes carrying charges on deferral and variance accounts. These amounts are backed out of the balance leaving just interest earned on OPDC cash balances in our bank account. Our agreement with our bank pays interest on daily cash balances at prime rate less 1.75%. Table 3-28 shows the monthly prime rate history from 2004 and calculates a simple monthly average. This amount less 1.75% is an estimate of the average rate earned on cash for each year.

When the average prime rate for the year is applied to an estimate of the average cash balance on hand for the year (average of the opening and closing) the result is close to actual interest earned for 2006 EDR, 2006 Actual and 2007 Actual. The result is lower than actual interest earned in 2008. OPDC paid a $3.5 million dividend to the parent company in August 2008, OPC, dropping the yearend cash balance significantly. The low interest amounts anticipated in 2009 and 2010 reflect low average cash balances for OPDC moving forward and low prime rates anticipated for 2009 and 2010.

Table 3-28: Interest Income Reconciliation For Reasonableness - From 2006 EDR To 2010 Test With Variances

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
INTEREST INCOME						
4405-Interest and Dividend Income	134,800	242,300	217,800	143,000	5,000	8,000
Less interest on variance accounts (1)	-	(44,600)	(10,200)	(11,800)	-	-
Earned on cash balances (2)	**134,800**	**197,700**	**207,600**	**131,200**	**5,000**	**8,000**

Interest Rates - Prime (3)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Prime rate - January	4.25%	4.25%	5.25%	6.00%	5.75%	3.00%	*2.25%*
Prime rate - February	4.25%	4.25%	5.25%	6.00%	5.75%	3.00%	*2.50%*
Prime rate - March	4.00%	4.25%	5.50%	6.00%	5.25%	2.50%	*2.50%*
Prime rate - April	3.75%	4.25%	5.75%	6.00%	4.75%	2.25%	*2.50%*
Prime rate - May	3.75%	4.25%	6.00%	6.00%	4.75%	2.25%	*2.75%*
Prime rate - June	3.75%	4.25%	6.00%	6.00%	4.75%	*2.25%*	*2.75%*
Prime rate - July	3.75%	4.25%	6.00%	6.25%	4.75%	*2.25%*	*2.75%*
Prime rate - August	3.75%	4.25%	6.00%	6.25%	4.75%	*2.25%*	*3.00%*
Prime rate - September	4.00%	4.50%	6.00%	6.25%	4.75%	*2.25%*	*3.00%*
Prime rate - October	4.25%	4.75%	6.00%	6.25%	4.00%	*2.25%*	*3.00%*
Prime rate - November	4.25%	4.75%	6.00%	6.25%	4.00%	*2.25%*	*3.25%*
Prime rate - December	4.25%	5.00%	6.00%	6.00%	3.50%	*2.25%*	*3.25%*
Prime Rate - Average	**4.00%**	**4.42%**	**5.81%**	**6.10%**	**4.73%**	**2.40%**	**2.79%**
Reduction from Prime	1.75%	1.75%	1.75%	1.75%	1.75%	1.75%	1.75%
Interest rate on cash	**2.25%**	**2.67%**	**4.06%**	**4.35%**	**2.98%**	**0.65%**	**1.04%**

Cash balance per fs (000's)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Opening - Jan 1	6,461	5,580	4,880	5,134	3,708	844	607
Closing - Dec 31	5,580	4,880	5,134	3,708	844	607	967
Average	**6,021**	**5,230**	**5,007**	**4,421**	**2,276**	**726**	**787**
Estimate of potential interest	135	139	203	192	68	5	8

Dividends declared and paid to parent company OPC

April	2,000	2,000	-	1,500	500	800	-
August	-	-	-	-	3,500	-	-

Notes

(1) Interest - carrying charges on variance account balances was included in 4405 . None projected for bridge and test years.

(2) OPDC earns interest on cash balances held in bank accounts at the rate of Prime - 1.75%

(3) Prime rates in italics are estimates

APPENDIX 3 – A

A copy of the IESO's 18 Month Outlook from June 2009 to November 2010 follows on the next 41 pages.

18-MONTH OUTLOOK

From June 2009 to November 2010

ieso

Power to Ontario. On Demand.

An Assessment of the Reliability and Operability of the Ontario Electricity System

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Executive Summary

Several factors on both the supply and demand side of Ontario's electricity sector are contributing to a relatively positive reliability outlook for the province over the next 18 months.

From a supply perspective, nearly 3,800 megawatts (MW) of new and refurbished supply is scheduled to come into service over the next 18 months. This new generation comprises a range of projects, including nuclear, thermal and renewable resources like wind and small-scale hydroelectric.

In addition to this new supply, Ontario's import capability will increase with completion of the first stage of the new interconnection between Ontario and Québec, scheduled to be in service in the summer of 2009. Additional transmission reinforcements in Québec scheduled to be in service by May 2010 will allow transfers up to 1,250 MW.

The current schedule calls for the return to service of two refurbished units at the Bruce Power plant in the second half of 2010. This will increase Ontario's electricity supply options, but some of this new supply may be constrained until the Bruce-to-Milton transmission line is completed, along with other transmission enhancements.

The economic downturn that began last fall has triggered a noteworthy drop in demand for electricity across North America. In Ontario, peak and energy demand have declined in recent months, in part, as wholesale industrial consumers have scaled back on consumption. Over the first three months of the year, wholesale industrial consumption of electricity dropped by approximately 20 per cent compared with the same period in 2008. Other factors affecting demand are the growth in embedded generation and the impacts of conservation. Although the North American economy is expected to recover in 2010, electricity demand is unlikely to recover within the Outlook period. Overall, electricity demand in Ontario is expected to decline by 4.0 per cent in 2009 and 0.3 per cent in 2010.

In recent months, supply and demand conditions contributed to periods of surplus baseload generation (SBG) from late March to mid-April 2009. These periods were accompanied by record low negative prices. A confluence of factors led to these conditions:

- Low demand due to the economic downturn, increased conservation and embedded generation, and relatively mild spring weather
- High availability and output of baseload generation, including nuclear, wind and hydroelectric generation driven by spring freshet (or snow melt)

- Planned transmission outages, including an outage on the New York interconnection, which significantly reduced Ontario's export capability

Surplus generation conditions will reappear at various times over the next 18 months, particularly when demands are low or baseload and intermittent generator production is high. Those periods may represent opportunities for large volume customers to take advantage of lower hourly prices through increased consumption.

The following table summarizes the planned scenario's peak demands for the upcoming seasons under the Normal and Extreme weather scenarios

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2009	24,351	26,454
Winter 2009-10	22,886	24,046
Summer 2010	24,160	26,348

Conclusions & Observations

The following conclusions and observations are based on the results of this assessment.

Overall

- The system is positioned to operate reliably over the Outlook period. There will be challenges associated with accommodating new facilities and growing surplus baseload generation.

Demand Forecast

- The current recession has significantly reduced electricity demand on the system. Both energy and peak demands are tracking much lower than a year ago. Although the economy is expected to recover in 2010, electricity demand will not due to structural change in the Ontario economy, higher levels of conservation and continuing growth in embedded generation.
- Lower energy and peak demand levels will act to enhance system reliability. Although high peak demands are likely under extreme weather conditions they should not pose any province-wide reliability concerns.
- The economic downturn has led to a reduction in base load demand. The impact is particularly evident overnight when weather sensitive loads are quite small. Therefore, the system is experiencing lower minimum demand levels. This can have operational impacts as lower minimum demands increase the likelihood of surplus base load generation.

Resource Adequacy

- A number of units are scheduled to return to service from planned outage before summer. Meeting these schedules is critical to maintaining adequate reserve levels over the summer season. Delays will have a negative impact to the reliability of the system.
- The Outlook demonstrates that the initial emission targets from coal-powered generation should be achievable over the next 18 month period without impacting on reliability, although the complete strategy for 2010 has not been confirmed.
- Resource adequacy assessments look at two different resource scenarios (Planned and Firm) and two different weather scenarios (Normal and Extreme). Results of the resource adequacy assessment are summarized in the matrix below.

	Normal Weather Scenario	Extreme Weather Scenario
Planned Scenario	• Reserves are higher than required for all but two weeks.	• There are 18 weeks where reserves are lower than required.
Firm Scenario	• There are four weeks when reserves are lower than required.	• There are 28 weeks where reserves are lower than required.

- Under the extreme weather scenario, periods where the forecast reserves are not sufficient to meet requirements may result in reliance on imports, the rejection of planned outages by the IESO, or the use of emergency operating procedures.

Transmission Adequacy

- The Ontario transmission system with the planned system enhancements and transmission outages is expected to be adequate to supply the demand under the extreme and normal weather conditions forecast for the Outlook period**.**
- The supply reliability under extreme weather conditions, in particular to the GTA, will be improved with the availability of Goreway Station, the combined cycle operation of Portlands Energy Center and, looking further ahead, by the addition of Halton Hills Generating Station.
- Several projects relating to local load supply improvements will be placed in service during the timeframe of this Outlook to help relieve loadings of existing transformer stations and provide additional transformer capacity for future load growth.
- The ongoing forced outage of BP 76 on the New York – Ontario interface at Niagara will result in a reduced total Ontario - New York import and export scheduling capability until the circuit's scheduled return to service in Q3 2010.
- The new Ontario-Québec interconnection commissioning now and is scheduled for service by the middle of 2009. Additional transmission reinforcements in Québec are scheduled to be in service in May 2010 which will allow transfers up to 1,250 MW.
- Transmission outages scheduled in this Outlook period in the Bruce, Niagara, Southwest and West zones will result in reductions to the transfer capability out of the Bruce area for periods of time. The resulting limit reductions along with the increase of available generation in those areas will result in bottled generation capacity in the Bruce and West zones. Outages in the Northeast and Northwest zones will cause a reduction of the EWTE limit that contribute to the amount of bottled generation expected to occur in these zones.
- With the availability of Greenfield Energy Center, St Clair Energy Center and Lambton GS resources in the first quarter of the 2009, transmission constraints may limit the ability to utilize resources in southwestern Ontario in conjunction with imports from Michigan. The frequency and magnitude of congestion could be further increased by transmission outages and weather conditions.

- Hydro One's plan to enhance the existing Mississagi TS and Algoma TS generation rejection schemes by the later part of 2009 will improve the power transfer capability of the transmission corridor east of Mississagi and reduce the bottling of resources west of Mississagi.
- The deregistration of facilities and subsequent retirement of the Niagara 25 Hz system is complete. The Northeast 25 Hz system is also expected to be retired by 2010.

Operability

- Surplus baseload supply situations have occurred more frequently this spring than in previous years and the expected frequency will increase further as more baseload generation is added to the system and minimum demand levels continue at low levels due to the combined impacts of current economic conditions and conservation.

- End of Section -

Caution and Disclaimer

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1.0 Introduction

This Outlook covers the 18-month period from June 2009 to November 2010 and supersedes the last Outlook released in March 2009.

The purpose of the 18-Month Outlook is:

- To advise market participants of the resource and transmission reliability of the Ontario electricity system;
- To assess potentially adverse conditions that might be avoided through adjustment or coordination of maintenance plans for generation and transmission equipment; and
- To report on initiatives being put in place to improve reliability within the 18-month timeframe of this Outlook.

The contents of this Outlook focus on the assessment of resource and transmission adequacy. Additional supporting documents are located on the IESO website at http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, using the described methodology. Readers may envision other possible scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgment in considering possible future scenarios.

The reader should be aware that Security and Adequacy Assessments are published on the IESO web site on a weekly and daily basis that progressively supersedes information presented in this report.

Readers are invited to provide comments on this Outlook report or to give suggestions as to the content of future reports. To do so, please contact us at:

- Toll Free: 1-888-448-7777
- Tel: 905-403-6900
- Fax: 905-403-6921
- E-mail: customer.relations@ieso.ca.

- End of Section -

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2.0 Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast was based on actual demand, weather and economic data through to the end of February 2009. The economic outlook has been updated based on the most recent data. Actual weather and demand data for March and April has been included in the tables.

Past outlooks have included both a planned and firm demand scenario. This outlook only presents the scenario where conservation, demand management and embedded generation are expected to grow over the forecast horizon. This is consistent with the previous planned demand scenarios.

2.2 Updates to Resources

Installed capacity has increased by 935 MW since the last Outlook as the following projects became operational:

- Lac Seul Hydroelectric Project (12 MW)
- St. Clair Energy Centre (678 MW MW)
- Portlands Energy Centre Combined Cycle Operation (245 MW)

The assessment uses planned generator outages as submitted by market participants to the IESO's Integrated Outage Management System (IOMS). This Outlook is based on submitted generation outage plans as of April 27, 2009.

2.3 Updates to Transmission Outlook

The list of transmission projects, planned transmission outages and actual experience with forced transmission outages have been updated from the previous 18-Month Outlook. For this Outlook, transmission outage plans submitted to the IOMS as of March 27, 2009 were used.

2.4 Updates to Operability Outlook

The IESO has begun to report on system operability issues as they affect reliability. This topic is expected to evolve and grow over time as the new supply mix unfolds. Surplus baseload assumptions have been enhanced over the previous Outlook.

- End of Section -

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3.0 Demand Forecast

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period June 2009 to December 2010 and supersedes the previous forecast released March 2009. Tables containing supporting information are contained in the 2009 Q2 Outlook Tables spreadsheet.

Demand is expected to decline over the forecast horizon. The economy is expected to hit its trough later this year before recovering late in 2010. In the near term both peak and energy demand will fall with the economic contraction. Economic recovery, as measured in GDP, will not coincide with a recovery in electricity demand. Both peak and energy demand will be lower due to structural changes in the Ontario economy, increased conservation and growth in embedded generation.

The following table shows the seasonal peaks and annual energy demand over the forecast horizon of the Outlook.

Table 3.1: Forecast Summary

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2009	24,351	26,454
Winter 2009-10	22,886	24,046
Summer 2010	24,160	26,348
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006 Energy	152.3	-1.9%
2007 Energy	151.6	-0.5%
2008 Energy	148.9	-1.8%
2009 Energy (Forecast)	142.9	-4.0%
2010 Energy (Forecast)	142.5	-0.3%

Forecast Details

The companion document, the Ontario Demand Forecast, looks at demand in more detail. It contains the following:

- details on the demand forecast,
- analysis of historical demand,
- a discussion on the drivers affecting demand.

The data contained in the Ontario Demand Forecast document are included in the Outlook – Table spreadsheet.

- End of Section -

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4.0 Resource Adequacy Assessment

This section provides an assessment of the adequacy of resources to meet the forecast demand. The key messages are:

- When reserves are below required levels with potentially adverse effects on the reliability of the grid, the IESO has the authority to reject outages based on their order of precedence.
- Conversely, an opportunity exists for additional outages when reserves are above required levels.

These actions address shortages and surpluses of reserves to a large extent.

In recognition of the uncertainty that exists regarding the future availability of resources, two resource scenarios are described in this section: the Firm Scenario and the Planned Scenario

Over the course of the Outlook period over 3,800 MW of new and refurbished supply is scheduled to come into service. Most of the new supply projects have started their commissioning phase or are in the construction phase. Additionally, the new interconnection with Québec will increase transfer capabilities by the middle of 2009.

The existing installed generating capacity is summarized in Table 4.1. This excludes capacity that is commissioning.

Table 4.1 Existing Installed Generation Resources as of May 5, 2009

Fuel Type	Total Capacity (MW)	Number of Stations	Change in Capacity (MW)	Change in Stations
Nuclear	11,426	5	0	0
Hydroelectric	7,835	69	12	0
Coal	6,434	4	0	0
Oil / Gas	7,582	25	923	1
Wind	704	6	0	0
Biomass / Landfill Gas	75	5	0	0
Total	34,056	114	935	1

4.1 Committed and Contracted Generation Resources

Table 4.2 summarizes generation that is scheduled to come into service, be upgraded or retired within the Outlook period. This includes generation projects in the IESO's Connection Assessment and Approval Process (CAA) that are under construction and projects contracted by the OPA. Details regarding the IESO's CAA process and the status of all projects in the CAA queue can be found on the IESO's web site at http://www.ieso.ca/imoweb/connassess/ca.asp.

The estimated effective date in Table 4.2 indicates the date on which additional capacity is assumed to be available to meet Ontario demand. For projects that are under contract, the estimated effective date is the best estimate of the date when the contract requires the additional capacity to be available. If a project is delayed the estimated effective date will be the best estimate of the commercial in-service date for the project.

Table 4.2 Committed and Contracted Generation Resources

Proponent/Project Name	Zone	Fuel Type	Estimated Effective Date	Change	Project Status	Capacity Considered in Scenario (MW)	
						Firm (MW)	Planned (MW)
Lac Seul Hydroelectric Project	Northwest	Water			In-Service		
Portlands Energy Centre Combined Cycle Operation	Toronto	Gas			In-Service		
LaSalle Recreation Centre	West	Oil	2009-Q2		Commissioning	1	1
St. Clair Energy Centre	West	Gas			In-Service		
Goreway Station Project	Toronto	Gas	2009-Q2		Commissioning	839	839
Algoma Energy Cogeneration Facility	Northeast	By-Product Gas	2009-Q2		Construction	63	63
Enbridge Ontario Wind Farm (formerly Underwood WGS or Leader Wind Power Projects)	Southwest	Wind	2009-Q2		Commissioning	182	182
Wolfe Island Wind Project	East	Wind	2009-Q3		Construction	198	198
Nuclear Upgrade	N/A	Uranium	2009-Q3		Construction	27	27
East Windsor Cogeneration Centre	West	Gas	2009-Q3		Construction		84
Retirement of Wawaitin 25 Hz generation to	Northeast	Water	2010-Q1		Connection Assessment	-11	-11
Thorold Cogeneration Project	Niagara	Gas	2010-Q2		Construction		236
Healey Falls	East	Water	2010-Q2		Construction		16
Bruce Unit 2	Bruce	Uranium	2010-Q3	Delayed	Construction		750
Raleigh Wind Energy Centre	West	Wind	2010-Q3		Approvals & Permits		78
Halton Hills Generating Station	Southwest	Gas	2010-Q3		Construction		632
Bruce Unit 1	Bruce	Uranium	2010-Q4	Delayed	Construction		750
Total						**1,299**	**3,845**

Notes to Table 4.2:

1. Shading indicates a change from the previous Outlook.
2. The total may not add up due to rounding. Total does not include In-Service facilities.
3. Project status provides an indication of the project progress. The milestones used are:
    a. Connection Assessment - the project is undergoing an IESO system impact assessment
    b. Approvals & Permits - the proponent is acquiring major approvals and permits required to start construction (e.g. environmental assessment, municipal approvals etc)
    c. Construction - the project is under construction
    d. Commissioning - the project is undergoing commissioning tests with the IESO

4.2 Summary of Scenario Assumptions

In order to assess future resource adequacy, the IESO must make assumptions on the amount of available resources. The Outlook considers two scenarios: a Firm Scenario and a Planned Scenario. Both scenarios' starting point is the existing installed resources shown in Table 4.1.

Under both scenarios, all existing resources and resources that are scheduled to come into service are assumed to be available over the study period, except for those units scheduled to retire and those for which the generator has submitted planned outages.

The generation capability assumptions are as follows:

- Hydroelectric capability (including energy and operating reserve) is based on median historical values during weekday peak demand hours from May 2002 to March 2009.
- Thermal generators' capacity and energy contributions are based on market participant submissions, including planned outages, expected forced outage rates and seasonal deratings.

- For wind generation the monthly Wind Capacity Contribution (WCC) values are used at the time of weekday peak, while total energy contribution is assumed to be 30%.

The Firm and Planned Scenarios differ in their assumptions regarding the amount of demand measures and generation capacity. These differences are summarized in the following table.

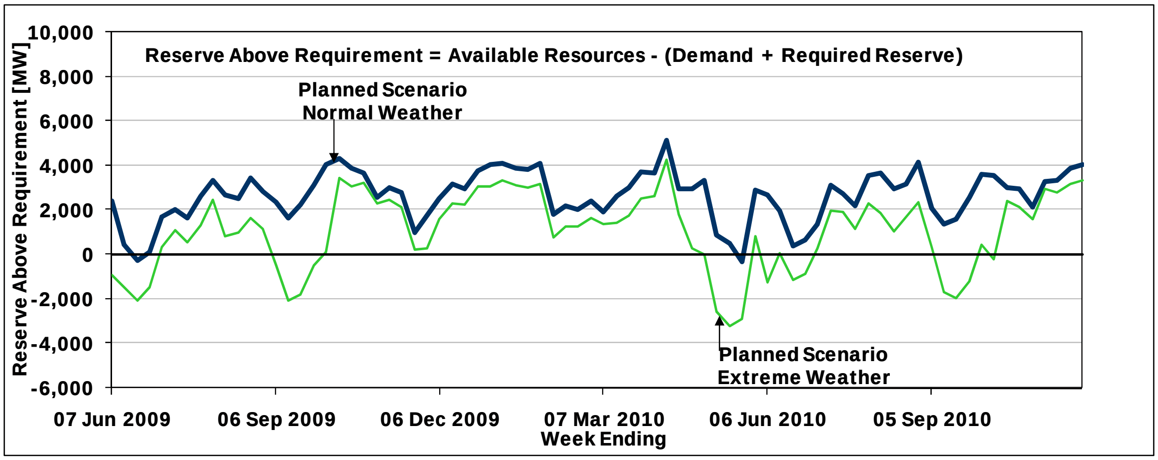
Table 4.3 Summary of Scenario Assumptions

Assumptions		Planned Scenario	Firm Scenario
Resource	Existing Installed Resources	Total Capacity	Total Capacity
		34,056 MW	34,056 MW
	New Generation and Capacity Changes	All	Only Capacity Changes, Commissioning Generators and Generators starting in the first 3 months
		3,845 MW	1,299 MW
Demand Forecast	Conservation	Incremental	
		Incremental growth of 215 MW at time of peak	
	Embedded Generation	Incremental	
		Incremental growth of 145 MW at time of peak	
	Demand Measures	Incremental	Existing
		624 MW	375 MW

4.3 Planned Scenario with Normal and Extreme Weather

Reserve Above Requirement levels, which represent the difference between Available Resources and Required Resources, are shown in Figure 4.1.

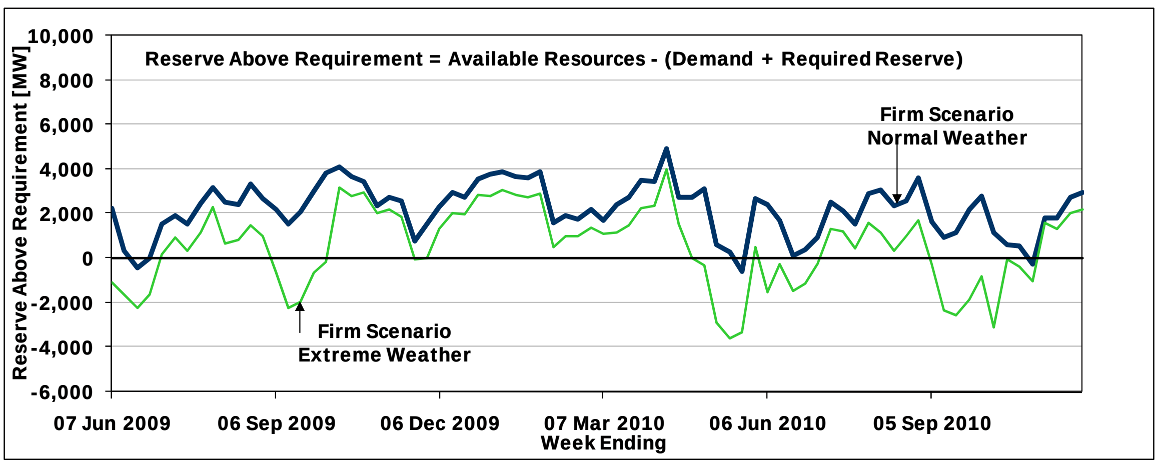
Figure 4.1 Reserve Above Requirement: Planned Scenario with Normal vs. Extreme Weather



4.4 Firm Scenario with Normal and Extreme Weather

Reserve Above Requirement levels, which represent the difference between Available Resources and Required Resources, are shown in Figure 5.2.

Figure 4.2 Reserve Above Requirement: Firm Scenario with Normal vs. Extreme Weather



4.5 Comparison of Resource Scenarios

Table 4.4 shows a snapshot of the forecast available resources, under the two scenarios, at the time of the summer and winter peak demands during the Outlook.

The monthly forecast of energy production capability, as provided by market participants, is included in the 2009 Q2 Outlook Tables Appendix A, Table A7.

Table 4.4 Summary of Available Resources

Notes	Description	Summer Peak 2009		Winter Peak 2010		Summer Peak 2010	
		Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario	Firm Scenario	Planned Scenario
1	Installed Resources (MW)	35,338	35,338	35,365	35,449	35,355	36,519
2	Imports (MW)	0	0	0	0	0	0
3	Total Resources (MW)	35,338	35,338	35,365	35,449	35,355	36,519
4	Total Reductions in Resources (MW)	6,148	6,148	5,957	6,041	6,250	6,958
5	Demand Measures (MW)	375	516	375	624	375	647
6	Available Resources (MW)	29,566	29,706	29,784	30,033	29,480	30,208

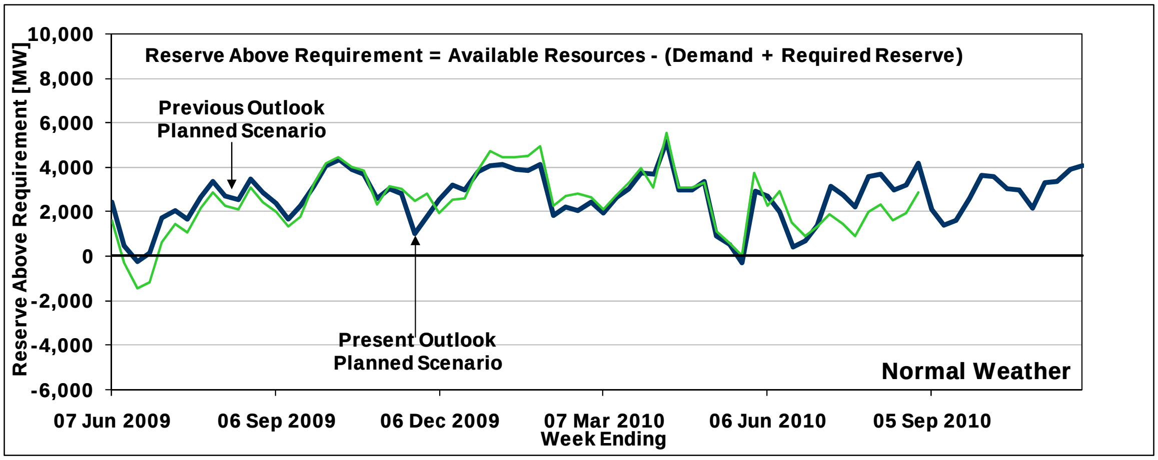
Notes to Table 4.4:

1. Installed Resources: This is the total generation capacity assumed to be installed at the time of the summer and winter peaks.
2. Imports: The amount of external capacity considered to be delivered to Ontario.
3. Total Resources: The sum of Installed Resources (line 1) and Imports (line 2).
4. Total Reductions in Resources: Represent the sum of deratings, planned outages, limitations due to transmission constraints, generation constraints due to transmission outages/limitations and allowance for capability levels below rated installed capacity.
5. Demand Measures: The amount of demand available to be reduced.
6. Available Resources: Equals Total Resources (line 3) minus Total Reductions in Resources (line 4) plus Demand Measures (line 5).

Comparison of the Weekly Adequacy Assessments for the Planned Scenario

Figure 4.3 provides a comparison between the forecast Reserve Above Requirement values in the present Outlook and the forecast Reserve Above Requirement values in the previous Outlook published on March 16, 2009. The difference is mainly due to the changes to generator outages and the change in the demand forecast.

Figure 4.3 Reserve Above Requirement: Planned Scenario with Present Outlook vs. Previous Outlook



Resource adequacy risks are discussed in detail in the "Methodology to Perform Long Term Assessments" (IESO_REP_0266).

- End of Section -

5.0 Transmission Reliability Assessment

This section provides an assessment of the reliability of the Ontario transmission system for the Outlook period. The transmission reliability assessment has three key objectives:

- To identify all major transmission and load supply projects that are planned for completion during the Outlook period and to present their reliability benefits.
- To forecast any reduction in transmission capacity brought about by specific transmission outages. For a major transmission interface or interconnection, the reduction in transmission capacity due to an outage condition can be expressed as a change in the base flow limit associated with the interface or interconnection.
- To identify equipment outage events on the grid that could require contingency planning by market participants or by the IESO. Planned transmission outages are reviewed in conjunction with major planned resource outages and the scheduled completion of new generation and transmission projects to identify transmission reliability risks.

5.1 Transmission and Load Supply Projects

The IESO requires transmitters to provide information on the transmission projects that are planned for completion within the 18 month period. Construction of several transmission reinforcements are planned for service during the Outlook period. Major transmission and load supply projects planned to be in service are shown in Appendix B. Projects that are in service or whose completion has been deferred well beyond the period of this Outlook are not shown. The list includes only the transmission projects that represent major modifications or are considered to provide significant improvement to system reliability. Minor transmission equipment replacements or refurbishments are excluded.

Demand growth over the last decade has resulted in some area loads reaching or exceeding the capability of the local transmission system. To address this problem and provide additional transmission capacity for future load growth, Ontario transmitters and distributors have initiated plans to build new or replace existing transformer stations and reinforce the transmission system as necessary.

Connection assessments performed by the IESO concluded that these proposed projects will provide relief to existing transformer stations, some of which are presently overloaded, and will improve the supply to various load areas. In some of these assessments the IESO found that the local transmission system may be reaching its maximum capability and identified the need for installation of local voltage support equipment. As a result, Hydro One has initiated the installation of low voltage capacitor banks at a number of transformer stations in the system.

Transmission assessments performed by transmitters in collaboration with distributors also identified transmission reinforcements required to ensure load supply reliability. These needed reinforcements were confirmed by the IESO during related connection assessments. Several of these transmission reinforcements are currently under construction or are to start construction soon.

5.2 Transmission Outages

The assessment of transmission outages is limited to those with a scheduled duration of greater than five days or to those outages that are part of a project where the combined scheduled duration is greater than five days. As the start time of the outage approaches, actual outage schedule and additional outage requirements, as well as outages with a scheduled duration of five days or less could impose further transmission capacity restrictions. Prior to approving and releasing an outage, the IESO will reassess the outage for potential system impacts, taking into account all current and forecasted conditions.

The IESO's assessment of the transmission outage plans is shown in Appendix C, Tables C1 to C10. In these tables, each element is assessed individually by indicating the possible impacts and the reduction in transmission interface and interconnection limits. Where multiple outages are scheduled during the same period, the combined effect of all outages on the reduction in transmission interface and interconnection limits is presented. Where multiple outages are scheduled during the same period and reliability is affected, the IESO will request the transmitter to reschedule some of the outages. The methodology used to assess the transmission outage plans is described in the IESO document titled "Methodology to Perform Long Term Assessments" (IESO_REP_0266).

The planned transmission outages are reviewed in correlation with major planned resource outages and scheduled completion dates of new generation and transmission projects. This allows the IESO to identify transmission system reliability concerns and to highlight those outage plans that need to be adjusted. A change to an outage may include rescheduling the outage, reducing the scheduled duration or reducing the recall time.

This assessment will also identify any resources that have potential or are forecast to be constrained due to transmission outage conditions. Transmitters and generators are expected to have a mutual interest in developing an ongoing arrangement to coordinate their outage planning activities. Transmission outages that may affect generation access to the IESO controlled grid should be coordinated with the generator operators involved, especially at times when deficiency in reserve is forecast. Under the Market Rules, where the scheduling of planned outages by different market participants conflicts such that both or all outages cannot be approved by the IESO, the IESO will inform the affected market participants and request that they resolve the conflict. If the conflict remains unresolved, the IESO will determine which of the planned outages can be approved according to the priority of each planned outage as determined by the Market Rules detailed in Chapter 5, Sections 6.4.13 to 6.4.18. This Outlook contains transmission outage plans submitted to the IESO as of March 27, 2009.

5.3 Transmission System Adequacy

Generally, IESO Outlooks identify the areas of the IESO controlled grid where the projected extreme weather loading is expected to approach or exceed the capability of the transmission facilities for the conditions forecast in the planning period. Where the loading was projected to exceed the capability of the transmission facilities, there is also an increased risk of load interruptions.

IESO continues to work with Hydro One and other Ontario transmitters, to identify the highest priority transmission needs, and to ensure that those projects whose in service dates are at risk are given as much priority as is practical, especially those addressing reliability needs for peak demand periods of this Outlook. IESO has also been working closely with the OPA to specify the transmission enhancements location, timing and minimum requirements to satisfy reliability standards.

Within the context of this approach, the Ontario transmission system with the planned system enhancements and known transmission outages is expected to be adequate to supply the demand under the extreme and normal weather conditions forecast for the Outlook period.

5.3.1 Toronto and Surrounding Area

The Greater Toronto Area (GTA) electricity supply is mainly provided by the Trafalgar, Claireville, Parkway and Cherrywood 500/230 kV autotransformers, Pickering generation station (GS) and other local resources as depicted in Figure 6.1. The availability of these facilities is critical to ensure reliable electricity supply for Toronto and surrounding area.

Figure 6.1 Greater Toronto Area Electricity System

The reliable supply of demand in the GTA under extreme weather conditions forecasted for the Outlook period requires a minimum number of autotransformers at Trafalgar, Claireville, Parkway and Cherrywood and Pickering units in service at rated capabilities. For summer 2009, all autotransformers and Pickering units are expected to be in service. The projected loadings on the Trafalgar, Claireville, Parkway and Cherrywood autotransformers are expected to be within their continuous capability with all transmission facilities and resources in the GTA in service. The presence of Portlands Energy Center and the expected completion of Goreway Station before June 2009 reduce the loadings of all GTA autotransformers and thereby, increase their spare capability.

Under summer 2009 normal and extreme weather conditions, loadings on the autotransformers are not expected to exceed their long term emergency capability following either the forced outages of any one GTA autotransformer and two Pickering units, or the forced outages of one Pickering unit and any two autotransformers. The presence of Goreway Station is critical to provide significant loading relief to Claireville TS in case of multiple autotransformer outages.

Subsequent autotransformer or generation outages or deratings could result in mitigating measures being required to reduce the remaining GTA autotransformers loadings within their long term emergency rating.

The 230 kV transmission corridor between Trafalgar TS and Richview TS which supplies Brampton, Mississauga and parts of Caledon and Halton Hills may become loaded above capability during summer 2009 under extreme weather conditions. The new Hurontario switching station and the expansion of the 230 kV lines from Cardiff TS are planned for service before summer 2010 and will relieve the loading of this corridor and alleviate this problem.

To be able to serve the load growth in the York Region, the new Holland transformer station, planned to be in service by mid 2009 is being commissioned. This area will be subsequently reinforced in 2011 with the addition of a new generation resource that was recently announced by the OPA.

Outages for the Claireville TS enhancement work continue in the first half of 2009. Some outages will reduce the limit on the Flow East to Toronto (FETT) transmission interface.

5.3.2 Bruce and Southwest Zones

Planned refurbishments at the Bruce generation station and new wind power resources in southwestern Ontario will increase generation capacity in the Bruce and Southwest zones. In the near term, transmission reinforcements that will increase the transfer capability out of Bruce include the up-rating of the Hanover to Orangeville 230 kV circuits and the installation of seven additional high voltage shunt capacitors at Buchanan, Middleport and Nanticoke.

In addition to the near-term reinforcements described above, interim measures are being planned for the time when Bruce is operated with seven and eight units before the proposed 500 kV double-circuit line between Bruce and Milton is available. The interim measures would include the installation of additional voltage control facilities at Nanticoke and when necessary, maximizing the available reactive power from Nanticoke units. These measures together with the new shunt capacitors and the deployment of the existing Bruce special protection system will further reduce the potential for constrained generation. In the longer-term, the proposed 500 kV line from Bruce to Milton would provide the required transmission capability to deliver the full benefits of the Bruce refurbishment project and the development of new renewable resources in southwestern Ontario.

The proposed 500 kV line from Bruce to Milton received the OEB approval for leave to construct on September 15, 2008. Hydro One has prepared a construction plan and related equipment outages are expected to start in the second quarter of 2009.

To prevent low voltage conditions in the 115 kV transmission system in the Woodstock area during summer extreme weather conditions. Hydro One is planning to add a new transformer station and a second supply point by extending the 230 kV transmission lines from Ingersoll to Woodstock area and installing a new 230/115 kV transformer station. These plans will provide an increased level of supply reliability, and support further load growth in the area.

Hydro One is currently undertaking major upgrade work at Burlington TS which will resolve limitations in the station's ability to supply the Burlington 115 kV area loads. The 230/115 kV autotransformer replacement was completed. The remaining work which includes the replacement of all 115 kV breakers and the replacement of limiting bus sections is scheduled to be completed by the end of Q2 in 2012. Hydro One has also recently identified deratings associated with some of their 115 kV load supply transformer stations in the Guelph area which resulted in load transfers to the Burlington and Detweiler 115 kV areas further aggravating the load supply reliability. Hydro One, the affected distributors and the IESO are actively working on mitigating both the short-term issues and implementing a long term solution to these problems.

5.3.3 Niagara Zone and the New York Interconnection

The completion date for transmission reinforcement from Niagara region into the Hamilton-Burlington area continues to be delayed and to affect the use of both the available Ontario generation in the Niagara area and imports into the province, particularly during hot weather and high demand periods.

The forced outage to the circuit BP76 on the Ontario-New York interconnection at Niagara continues to reduce the total Ontario-New York import and export capability until its scheduled return to service in Q3 of 2010.

5.3.4 East Zone and Ottawa Zone

The new interconnection between Hawthorne transformer station (TS) in Ontario and Outaouais station in Québec is commissioning now and is scheduled for service by middle of 2009. The new interconnection is designed for an ultimate capacity of 1,250 MW but for most of the Outlook period the import and export capability could be limited to less than the nominal capacity depending on level of load and generation in the Outaouais region. After the completion of transmission reinforcement work in Québec, anticipated for May 2010, the interconnection will be able to operate up to its nominal capacity. The interconnection will be accompanied by the installation of a new Special Protection System (SPS) at Hawthorne TS and modifications to the existing SPS at St. Lawrence TS. The SPSs will allow simultaneous imports from Québec and New York to be maximized. The existing functionality of the St. Lawrence SPS will be maintained.

The current Reliability Must Run (RMR) contract between the IESO and Ontario Power Generation for Lennox GS covers the period October 2008 to September 2009. Lennox GS is presently needed to maintain local area reliability in the Ottawa zone and the area of Ontario that is located east of the FETT transmission interface. As part of the interconnection work at Hawthorne, the addition of voltage support facilities may reduce reliance on Lennox for local Ottawa zone needs. Similarly, supply improvements from new generation additions and conservation in and around Toronto through 2010 are expected to reduce the need for Lennox to control flows on the FETT interface. Therefore, the reliance on Lennox for local area reliability is expected to decrease starting with the second half of 2009. The IESO will continue to monitor any material changes in the load forecast and resource availability, and if necessary, reassess the need for another RMR contract. However, Lennox GS is also required for provincial resource adequacy, and must be retained or replaced. This resource adequacy requirement cannot be achieved through an RMR under the current Market Rules. The Integrated Power System Plan filed by the OPA with the OEB in August, 2007 assumes that Lennox remains in service and is categorized as a planned gas resource starting in 2011.

A new 230 kV section was added at Gardiner TS in preparation for connecting Wolfe Island wind farm which is currently under construction, expected to go in service during Q3, 2009.

5.3.5 West Zone and the Michigan Interconnection

With the availability of Greenfield, St Clair and Lambton resources in the second quarter of the 2009, transmission constraints in this zone may restrict resources in southwestern Ontario and imports from Michigan. This is evident in the bottled generation amounts shown for the Bruce and West zones in Tables A3 and A6.

Phase angle regulators (PARs) are installed on the Ontario-Michigan interconnection at Lambton TS, representing two of the four interconnections with Michigan, but are not currently operational until completion of agreements between the IESO, the Midwest ISO, Hydro One and International Transmission Company. The expected in service date is not known at the time of this Outlook. The operation of the these PARs along with the PAR on the Ontario-Michigan interconnection near Windsor will control flows to a limited extent, and assist in the management of system congestion..

The capability to control flows on the Ontario-Michigan interconnection between Scott TS and Bunce Creek is unavailable. The PAR installed at Bunce Creek in Michigan has failed and is scheduled for replacement in 2010.

Two transmission outages will result in Michigan – Ontario transfer capability to be reduced. The 230 kV circuit J5D outage between September 21, 2009 and October 9, 2009 will penalize the transfer limit by about 350 MW in directions, import and export. Between October 19, 2009 and November 27, 2009, the L4D 230 kV circuit outage will reduce the transfer capability by 190 and 550 MW, import and export, respectively.

5.3.6 Northeast and Northwest Zones

The transmission corridor east of Mississagi TS has been experiencing increased congestion due to the addition of new resources and lack of transmission reinforcements. It is expected that congestion will increase even further when projects currently under construction in the area will become operational.

For the near–term, the IESO has recommended that the existing Mississagi generation rejection scheme be enhanced as soon as possible to alleviate constrained generation west of Mississagi and to reduce congestion over the North-South transmission corridors. Hydro One is planning to implement the required modifications by the third quarter of 2010.

In the second half of 2009, extensive line work on 230 kV transmission circuits west of Mackenzie transformer station continues. This series of outages will reduce the Ontario-Manitoba and Ontario-Minnesota interconnection transfer capacity and also the East-West transmission interface capability. The reduction of the East-West Transfer East (EWTE) limit will contribute to the increased amount of bottled generation in the Northwest zone.

At the beginning of March 2009 one 500/230 kV autotransformer failed at Porcupine TS. The replacement unit is scheduled to go in service before the end of Q3 2009. Until then, upon failure of the remaining transformer the 230 kV customers supplied from Porcupine TS may be required to reduce their loading for a period of up to 20 days. Hydro One is continuously monitoring this remaining transformer to detect early signs of a possible failure and therefore reduce, possibly eliminate the full load restoration time.

Close to the end of March 2009 ten transmission towers collapsed due to ice accumulation on the 230 kV Marathon TS to Lakehead TS double circuit line resulting in additional bottled generation in the Northwest zone and significantly reduced import/export capability to Manitoba and Minnesota. The circuits were restored at full capability on temporary wood structures at the beginning of April.

5.3.7 Ontario 25 Hz System

The Niagara 25 Hz system was de-energized on April 30, 2009, when Units 1 and 2 at Beck#1 GS were decommissioned. The decommissioning of the entire system is well underway and expected to be completed during Q2 of 2009.

In northeastern Ontario, the 25 Hz system will also be retired. It is expected that the remaining facilities will be deregistered before the end of this Outlook period. There are no longer any 25 Hz loads in this area.

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6.0 Operability Assessment

The IESO monitors existing and emerging operability issues that could potentially impact system reliability. This Outlook continues its focus on surplus baseload generation (SBG). Over the next 18 months, low overnight demand and significant additions to baseload generation capacity are expected to contribute to an increase in the frequency of SBG, especially over the summer months.

SBG conditions typically arise during periods of low demand. Certain types of generation such as nuclear and some hydroelectric generators must maintain minimum output levels to ensure generation is available in future high demand hours; or to respect environmental, operational or safety constraints. In addition, intermittent and self-scheduling generation may inject power into the grid during low demand periods. Intermittent generation, such as wind or landfill gas, operates whenever its “fuel” is available. Self-scheduling generation, such as combined heat and power (CHP) and commissioning generators, may also choose to operate during periods of low demand. At the same time, transmission line outages can exacerbate SBG by reducing or eliminating the flow of electricity on key circuits, at times impacting Ontario’s ability to export surplus generation.

From late March to mid-April 2009, Ontario experienced extended periods of SBG during overnight hours, weekends, and the Easter holiday. These conditions were the result of a combination of factors (as described above):

- low demand,
- high availability/output of baseload generation; and
- an outage on the Ontario to New York interconnection circuits at Niagara that reduced export capability to zero MW, and also limited Ontario to Michigan export capability.

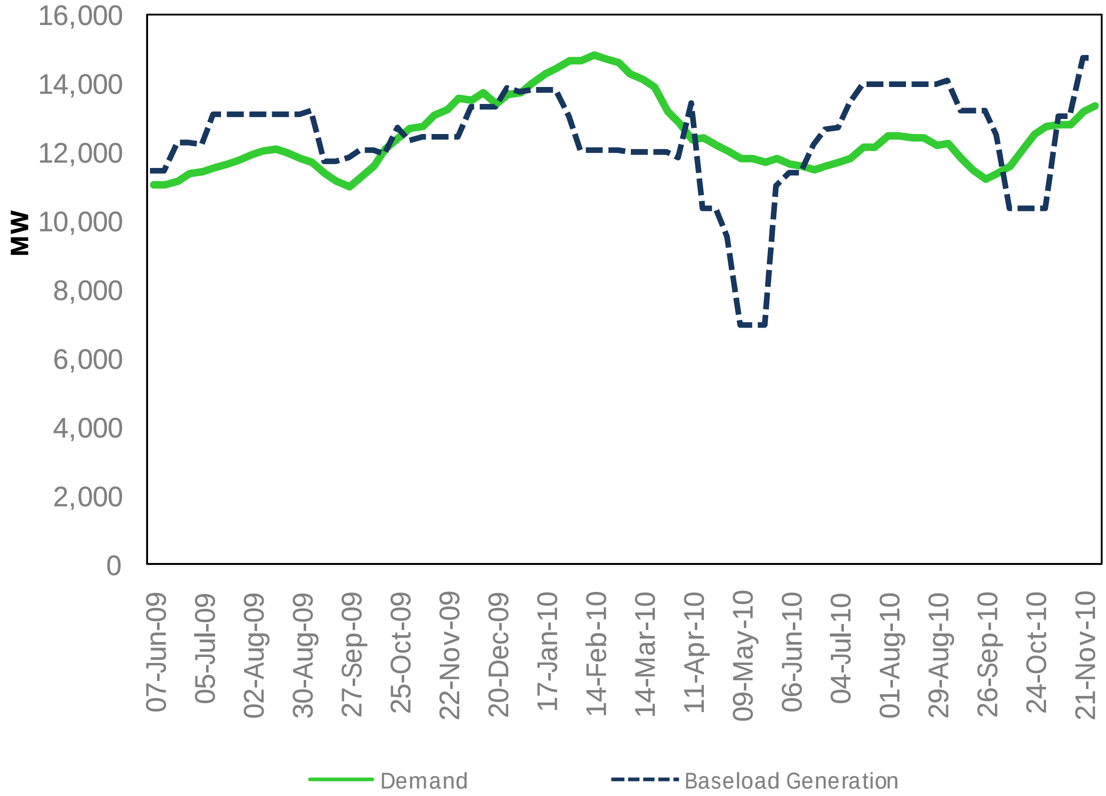
As noted in section 7.4, this period of SBG was accompanied by record low negative prices, a signal to the market of the prevailing over-generation conditions.

Figure 6.1 shows projected weekly minimum demand against the expected level of baseload generation. The baseload generation line has been updated from the previous Outlook to include expected self-scheduling and intermittent generation (in addition to nuclear, baseload hydroelectric and wind). The analysis also includes an assumption of 1,000 MW of exports. From Figure 6.1, it is clear that low minimum demands and high availability of baseload generation are especially prevalent in summer 2009 and 2010.

The expected output from commissioning units is explicitly excluded from this analysis due to uncertainty associated with commissioning schedules, as well as the highly variable nature of commissioning units. Readers are invited to make assumptions regarding commissioning generation based on expected in-service dates presented in Table 4.2.

Because of the impact surplus baseload generation can have on system and market operations, proper management of these occasions is a top priority for the IESO. The IESO is actively engaged with market participants to review and enhance the processes for managing these conditions.

Figure 6.1 Minimum Demand and Baseload Generation



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7.0 Historical Review

This section provides a review of past power system operation, including the most recent months of operation, to identify noteworthy observations, emerging problems and variations from forecast.

7.1 Weather and Demand Historical Review

Since the last forecast the actual demand and weather data for March and April has been recorded. Overall, the weather experienced this year has been near normal. For the first four months actual energy demand has been 5.3% lower than the previous year. On a weather-corrected basis that figure is -5.9%. The decline is slightly overstated due to the fact that 2008 was a leap year and had an extra day's worth of electricity demand. So far, economic factors have far out-weighed any weather impacts through the beginning of 2009. This has been evidenced in the wholesale customers' consumption which has dropped 21% compared to the first four months of 2008.

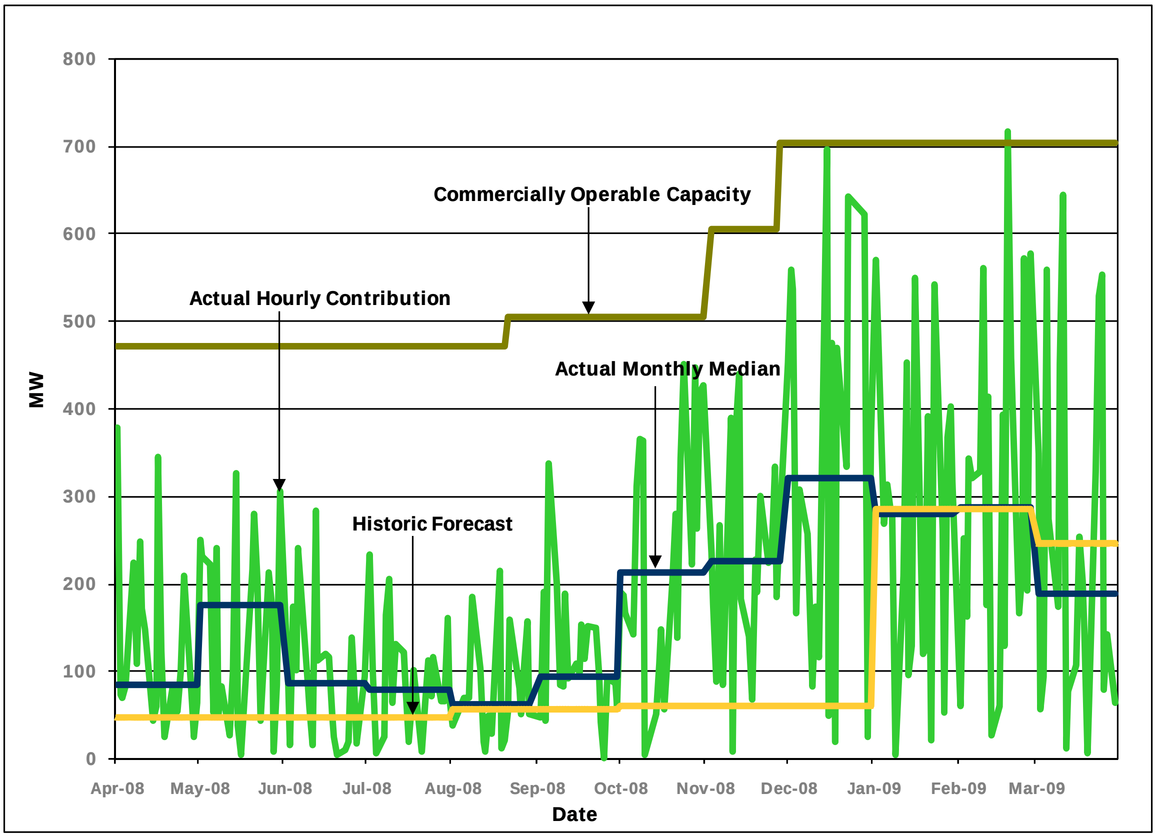
7.2 Hourly Resource Contributions at Time of Weekday Peak

The figures from 7.2.1 to 7.2.7 show the contributions made by wind generators, hydro generators, imports, and net interchange into Ontario at the time of weekday peak. A period of April 1, 2008 to March 31, 2009 was analyzed. Historical data of up to four years is also provided to highlight certain trends that were observed. Holiday data was not considered in the analysis since hydro peaking generation and interchange data during this timeframe is not typical of periods of time when Ontario may be challenged from a supply adequacy perspective.

7.2.1 Wind Contributions

Figure 7.2.1 indicates the amount of wind contribution to the wholesale market at the time of weekday peak, compared to the forecast contributions. For the time period of April 1, 2008 to December 31, 2008 the IESO forecasted available wind generation as 10 percent of installed capacity, assuming a constant contribution over a yearly basis. The forecast methodology has since been revised effective January 1, 2009 to take into account seasonal variances in wind patterns, among other factors. Wind generation increased from the previous year; however that can be directly attributed to the increase in operable capacity.

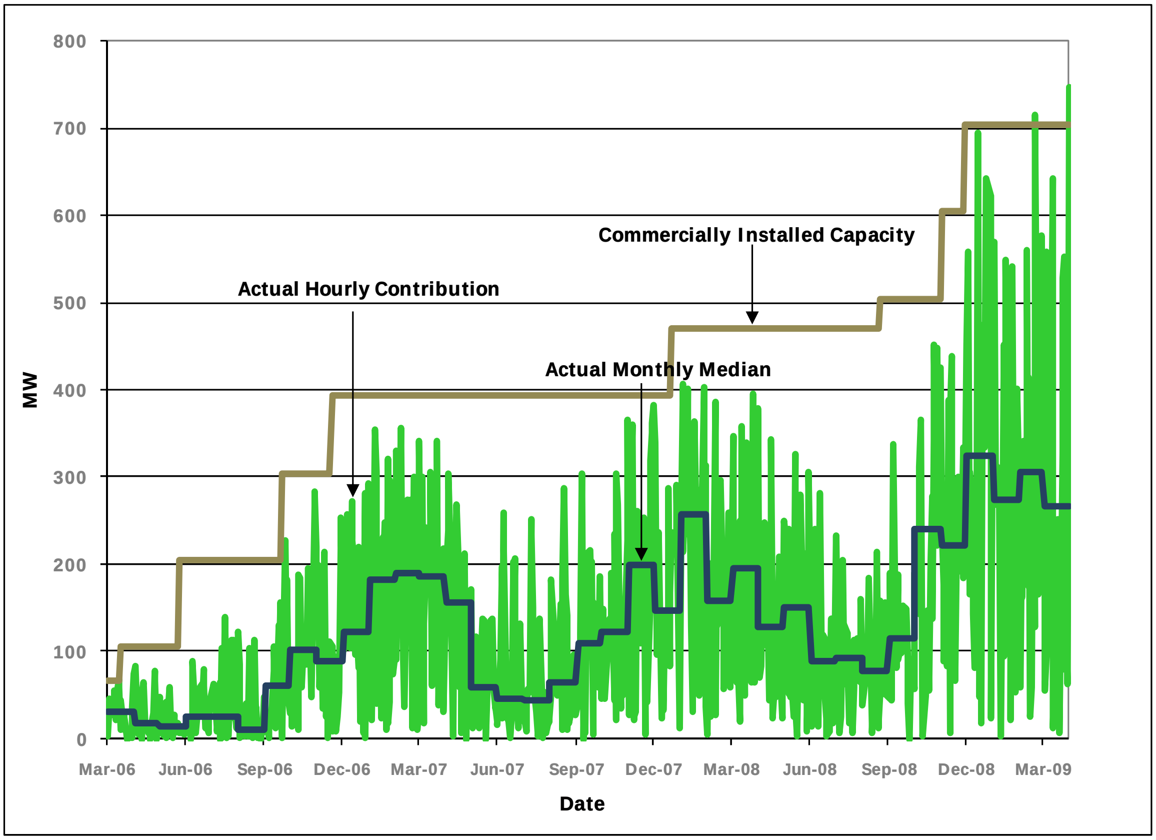
Figure 7.2.1 Wind Contributions at the Time of Weekday Peak



Note: Commercially operable capacity does not include commissioning units. Therefore actual hourly contribution may exceed commercial capability.

Figure 7.2.2 is a graph showing wind contributions in the past three years. Wind did not start commissioning in Ontario until February of 2006. Again, the increase in generation can be directly attributed to the increase in wind generating capability in the province.

Figure 7.2.2 Wind Contributions at the Time of Weekday Peak for the Past Three Years



7.2.2 Hydroelectric Contributions

Figure 7.2.3 indicates the amount of hydroelectric contributions to energy and operating reserve markets at the time of weekday peak, excluding weekends and holidays, compared to the forecasted contributions. The forecasted monthly median consists of the median contribution of hydroelectric energy at the time of weekday peak since 2002. Although 2008 was a record year for hydroelectric energy and the summer saw high production levels, the capacity contributions at peak often were below the long-term average levels, particularly following the summer.

Figure 7.2.3 Hydro Contributions (Energy and Operating Reserve) at the Time of Weekday Peak

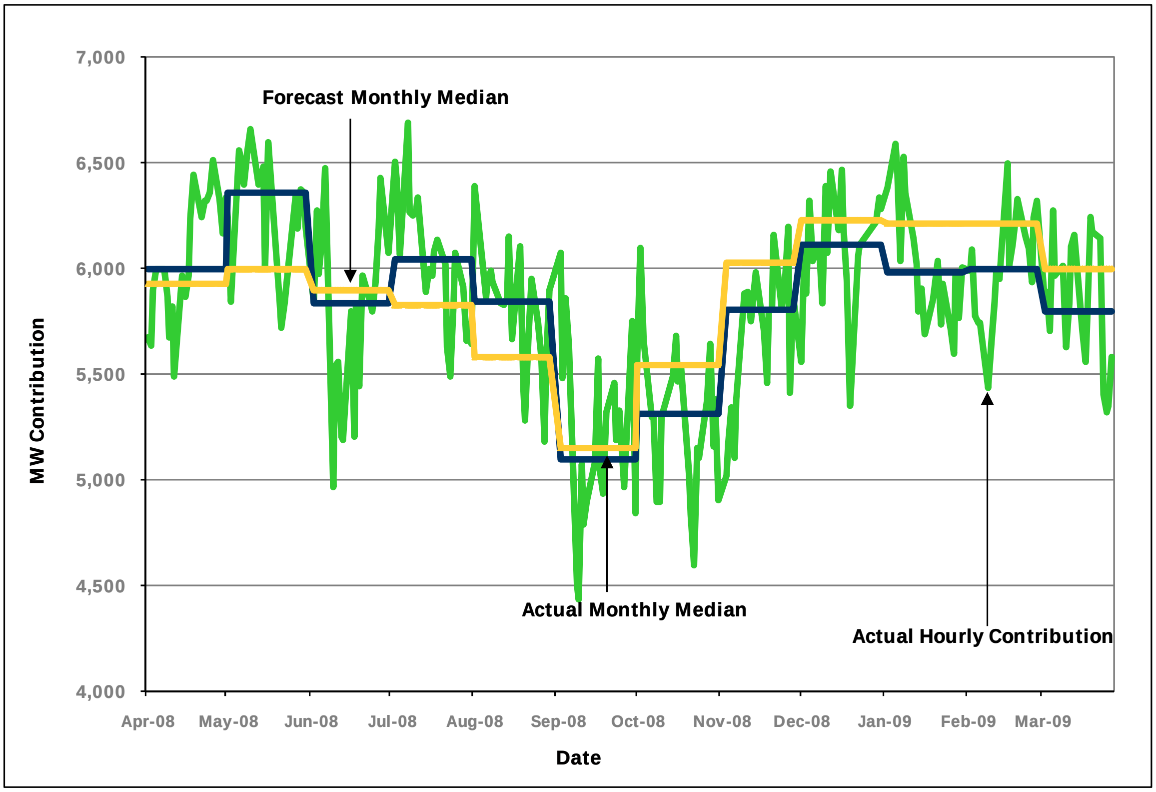
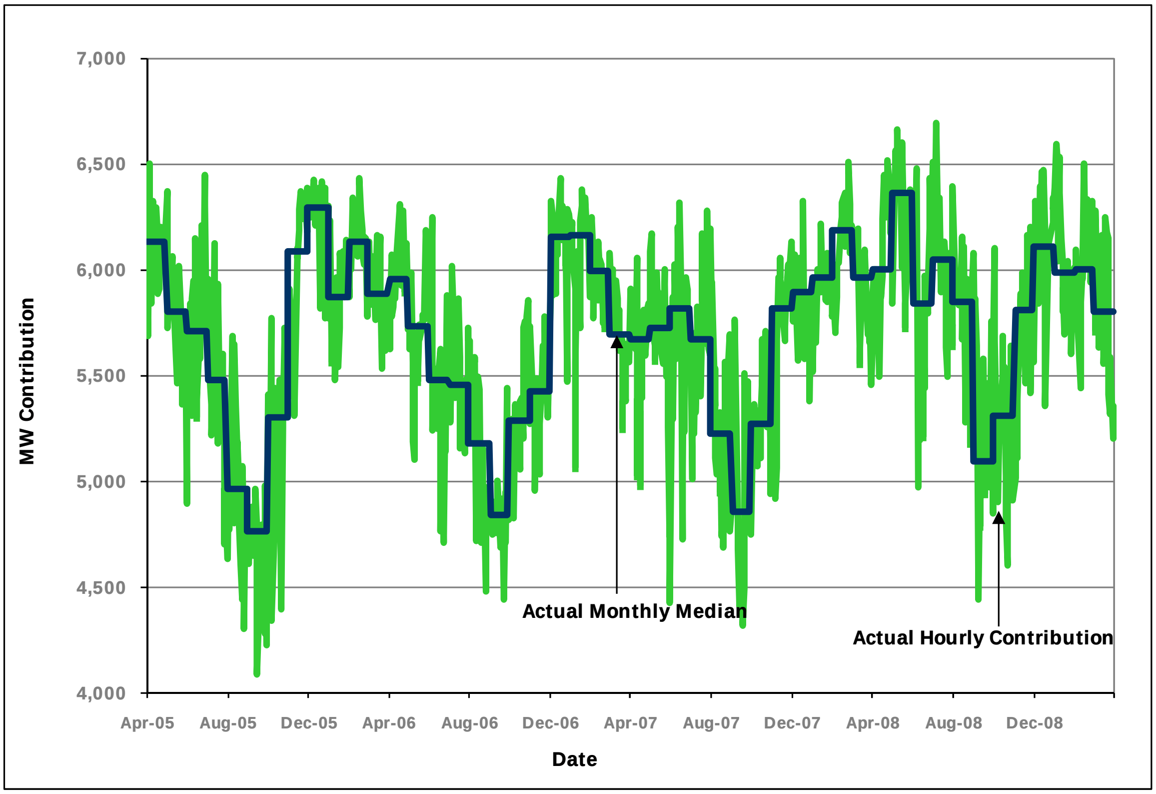


Figure 7.2.4 shows the amount of hydroelectric energy produced at time of weekday peak for the past four years. Due to higher than normal precipitation levels in Ontario, the peak hydro contribution was consistently elevated over the previous year's contribution by an average of 290 MW during the summer months. In June however, the loss of a major circuit restricted the ability to dispatch hydro resources in the Northeast resulting in a decreased aggregate hydro generation contribution for that month. The total energy production in 2008 of hydroelectric energy was significantly higher at 38.33 TWh compared to 33.44 TWh in 2007, 34.82 TWh in 2006 and 34.24 TWh in 2005.

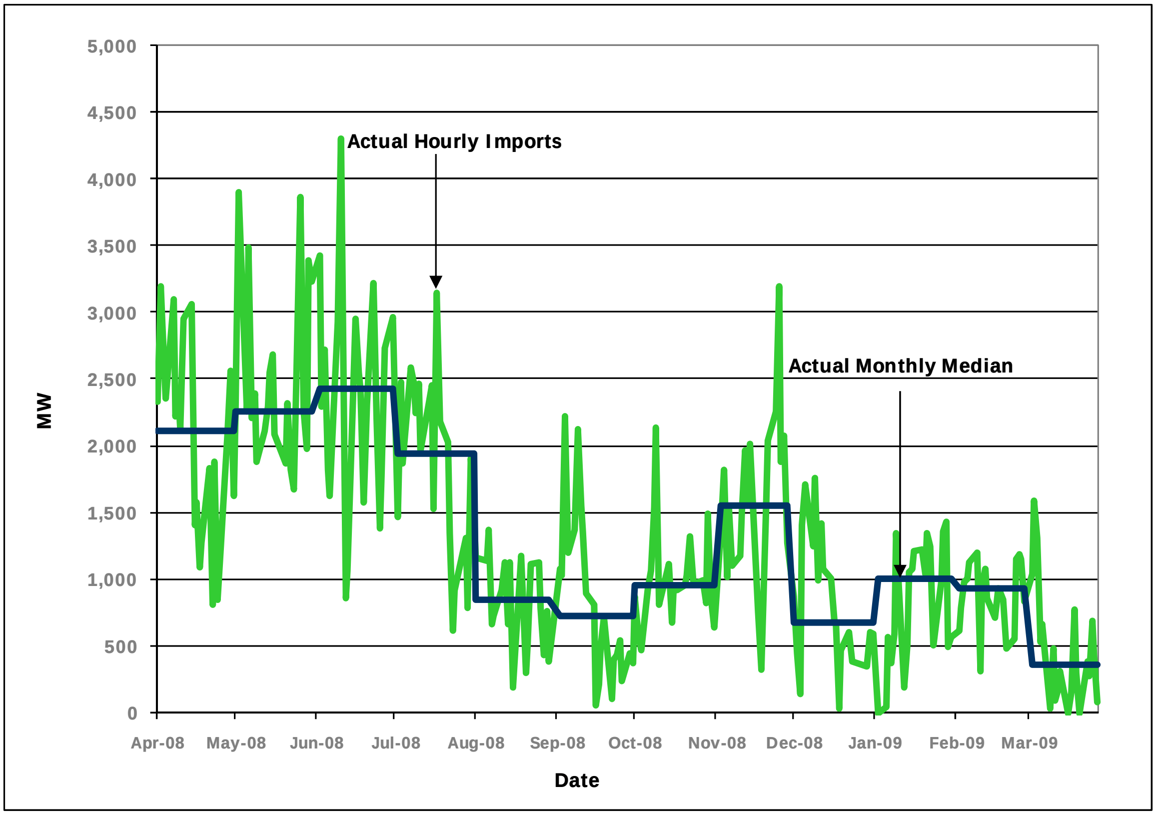
Figure 7.2.4 Hydro Contributions (Energy and Operating Reserve) at the Time of Weekday Peak for the Past Four Years



7.2.3 Imports into Ontario

Figure 7.2.5 shows imports into Ontario at the time of weekday peak. Imports were relatively low in this study period compared to the previous year's study period, especially during the last 6 months of the year. Low demands resulted in lower prices. Additionally, a sudden drop can be seen in imports in August 2008, with no corresponding reduction in net transactions. This is directly attributable to New York filing a Federal Energy Regulatory Commission (FERC) tariff which prohibited linked wheel transactions through their jurisdiction. Since many of these transactions were sourced from New York and were received at PJM, their removal caused no variation to Ontario's net transactions. However, when analyzing imports in isolation as in the figure below, this drop can be seen.

Figure 7.2.5 Imports into Ontario at the Time of Weekday Peak



7.2.4 Net Interchange into Ontario

Figure 7.2.6 shows the amount of net imports into Ontario at the time of weekday peak, excluding weekends and holidays. Net Interchange is the difference between total imports into Ontario and total exports out of Ontario. Ontario was mostly a net exporter for the entire study period. This is a deviating trend from the past as generally in the past, Ontario has been a net importer for at least part of the peak periods. This non-reliance on imports can be explained by the abundance of baseload generation Ontario has had as a result of significant hydro resources as well as lower than normal primary demands during those typically peak periods.

Figure 7.2.6 Net Interchange into Ontario at the Time of Weekday Peak

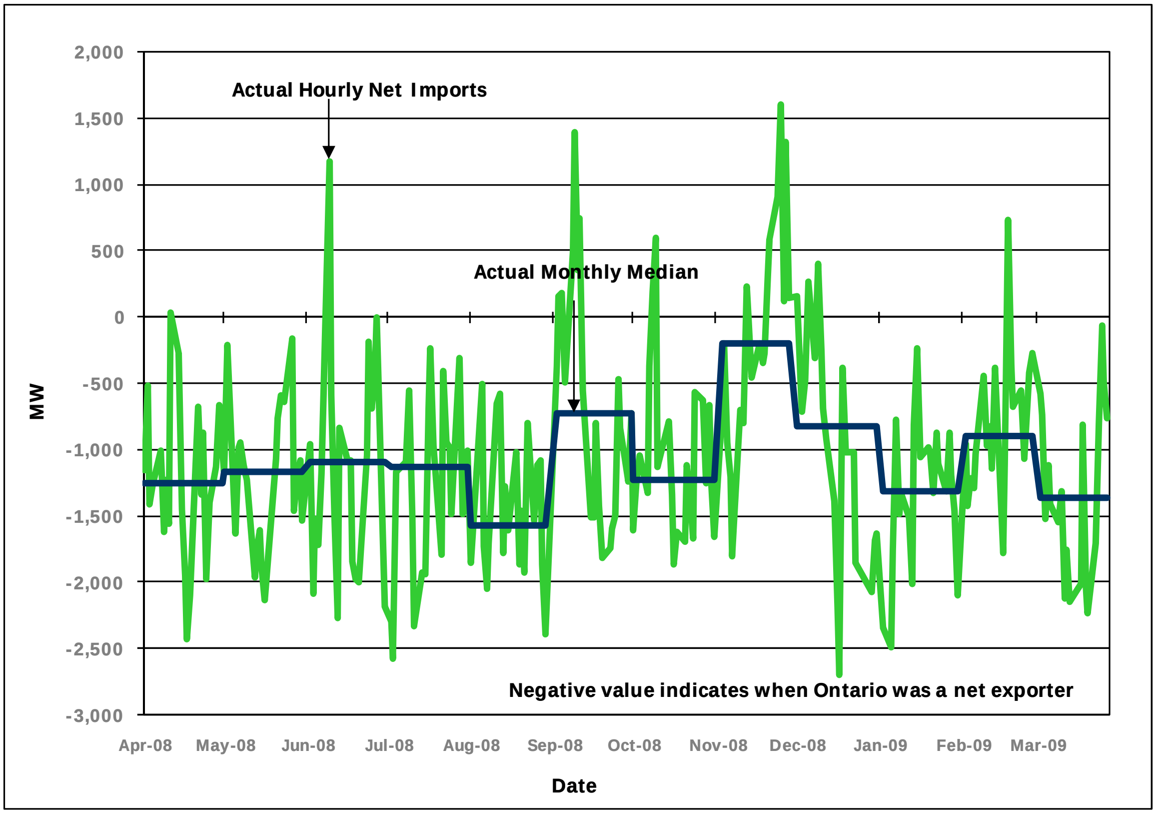
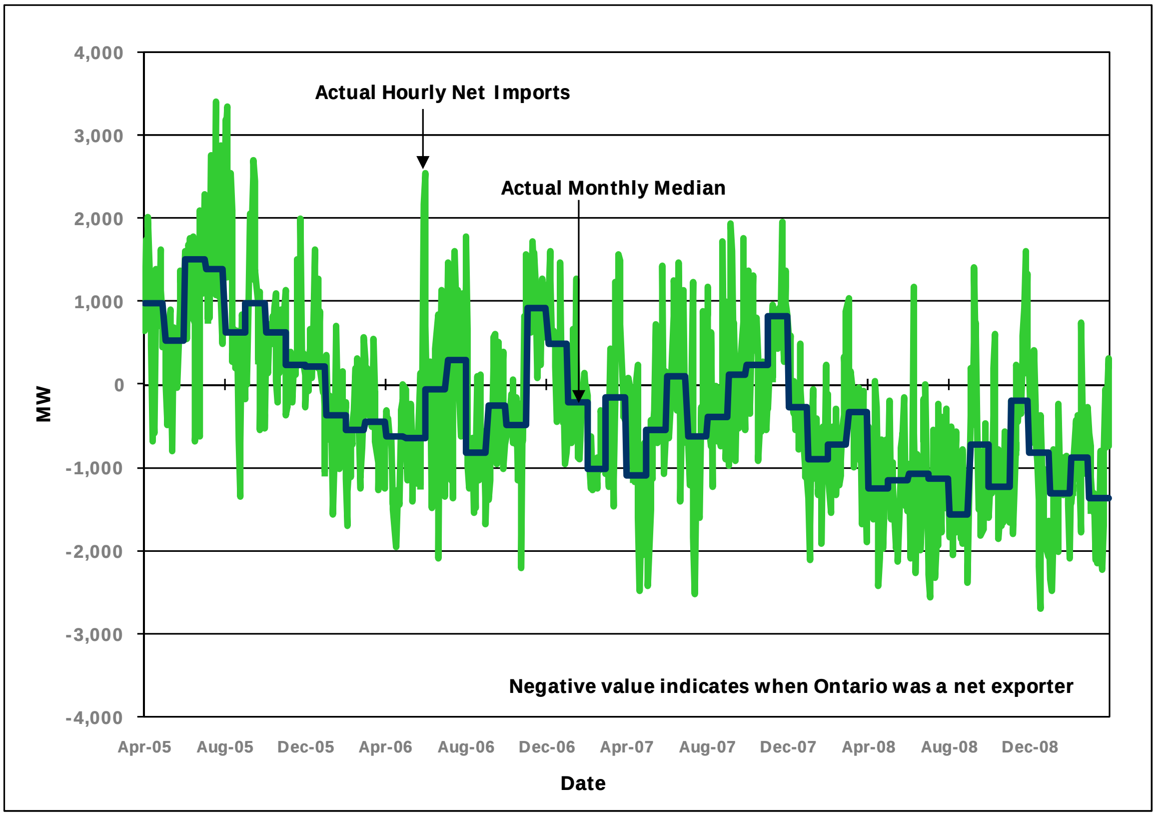


Figure 7.2.7 shows the amount of net imports into Ontario at the time of weekday peak, excluding weekends and holidays, for the past four years. Ontario's shift from net importer in 2005 to net exporter last year can be seen.

Figure 7.2.7 Net Interchange into Ontario at the Time of Weekday Peak for the Past Four Years



7.3 Generation/Transmission Disturbance Incidents

On March 25, 2009 circuits M23L, M24L, W21M and W22M were automatically removed from service resulting in an East-West Separation, disconnecting Northwestern Ontario from the rest of the Ontario system. The Northwestern system remained synchronously tied to both Manitoba and Minnesota by K21W/K22W and F3M. Manitoba and Minnesota scheduling limits were reduced to respect the operating security limits newly derived as a result of the contingency.

7.4 Negative Prices

During 2008, Ontario saw several instances where the Ontario Hourly Energy Price (HOEP) was negative, reaching a peak low of -$32.66. These prices were the result of lower demand conditions than forecast and low-priced generation resources offered to meet this market demand. The summer of 2008 saw unusually low prices (which were at times negative) as a result of low demand caused by milder than normal temperatures as well as an increase in production of hydroelectric baseload generation. There was a higher than normal amount of hydroelectric resources available during that period as a result of heavy snowfall during the winter and heavy rain throughout the spring and summer. This created an abundance of water which needed to flow and not spill for regulatory reasons. Prior to 2008, there had only been five instances of negative pricing in the province.

So far from January to March 2009, there have been 58 instances of negative pricing with a new peak low of -$51.00; all of which occurred during the last week of March. The negative prices can be attributed to lower demand conditions and low-priced baseload generation. The phenomenon was further exacerbated by a significant transmission outage which limited Ontario's ability to export. This outage resulted in a zero MW schedule with NY and a reduced scheduling limit with Michigan, limiting exports out of the province. The IESO, during these times, was required to dispatch down baseload generation that is not typically maneuvered. Generators were dispatched economically, according to offer prices.

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APPENDIX 3 – B

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix B on the next three pages.

	Purchased (including transmission losses)	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Population	Number of Peak Hours	Blackout Flag	**Predicted Purchases**
Jan-96	32,105,791	839	0	94.72	31	0	27,740	352	0	31,008,012
Feb-96	29,375,921	740	0	94.80	29	0	27,761	336	0	28,578,021
Mar-96	27,990,632	669	0	94.89	31	1	27,782	336	0	28,154,857
Apr-96	24,835,090	455	0	94.97	30	1	27,804	336	0	24,888,173
May-96	22,198,746	209	7	95.06	31	1	27,825	352	0	22,628,516
Jun-96	21,319,575	35	33	95.14	30	0	27,846	320	0	21,269,115
Jul-96	21,362,288	11	44	95.23	31	0	27,867	352	0	22,139,061
Aug-96	22,271,997	6	72	95.32	31	0	27,889	336	0	23,081,263
Sep-96	21,640,512	84	24	95.40	30	1	27,910	320	0	21,011,865
Oct-96	23,341,016	285	0	95.49	31	1	27,931	352	0	23,462,904
Nov-96	26,467,678	548	0	95.57	30	1	27,952	320	0	26,131,417
Dec-96	28,001,689	606	0	**95.66**	31	0	27,974	320	0	27,997,111
Jan-97	32,195,226	836	0	96.01	31	0	27,995	352	0	31,242,393
Feb-97	27,794,810	680	0	96.37	28	0	28,016	320	0	27,442,682
Mar-97	28,681,746	678	0	96.73	31	1	28,037	304	0	28,326,320
Apr-97	24,697,796	410	0	97.08	30	1	28,059	352	0	24,717,237
May-97	23,004,325	262	0	97.44	31	1	28,080	336	0	23,236,426
Jun-97	22,048,512	12	55	97.81	30	0	28,101	336	0	22,231,034
Jul-97	22,949,266	20	83	98.17	31	0	28,122	352	0	24,096,689
Aug-97	21,838,602	22	30	98.53	31	0	28,144	320	0	21,868,390
Sep-97	21,553,663	89	6	98.90	30	1	28,165	336	0	20,819,109
Oct-97	23,692,543	297	1	99.26	31	1	28,186	352	0	23,985,668
Nov-97	25,859,942	488	0	99.63	30	1	28,207	304	0	25,578,639
Dec-97	28,466,507	636	0	**100.00**	31	0	28,229	336	0	28,860,136
Jan-98	29,684,937	726	0	100.39	31	0	28,250	336	0	30,057,732
Feb-98	25,970,015	562	0	100.79	28	0	28,271	320	0	26,277,384
Mar-98	27,611,778	554	0	101.18	31	1	28,292	352	0	27,429,369
Apr-98	22,836,420	315	0	101.58	30	1	28,314	336	0	23,730,616
May-98	22,137,214	55	19	101.98	31	1	28,335	320	0	21,555,606
Jun-98	23,047,616	58	66	102.38	30	0	28,356	352	0	23,745,359
Jul-98	23,767,435	3	83	102.78	31	0	28,377	352	0	24,226,099
Aug-98	23,918,674	4	82	103.18	31	0	28,399	320	0	24,004,517
Sep-98	22,386,203	57	21	103.59	30	1	28,420	336	0	21,390,602
Oct-98	23,450,183	250	0	104.00	31	1	28,441	336	0	23,604,300
Nov-98	25,892,881	445	0	104.40	30	1	28,462	336	0	25,634,645
Dec-98	28,191,248	613	0	**104.81**	31	0	28,484	336	0	28,930,526
Jan-99	31,666,721	830	0	105.45	31	0	28,505	320	0	31,664,154
Feb-99	27,090,989	511	0	106.09	28	0	28,526	320	0	26,000,675
Mar-99	28,482,443	508	0	106.73	31	1	28,547	368	0	27,339,793
Apr-99	23,331,665	335	0	107.38	30	1	28,569	336	0	24,387,986
May-99	22,378,288	113	9	108.03	31	1	28,590	320	0	22,293,164
Jun-99	24,158,736	30	62	108.68	30	0	28,611	352	0	23,631,721
Jul-99	24,881,874	4	129	109.34	31	0	28,632	336	0	26,359,499
Aug-99	23,615,877	19	42	110.00	31	0	28,654	336	0	23,192,187
Sep-99	23,109,298	76	38	110.67	30	1	28,675	336	0	22,723,475
Oct-99	24,336,330	306	0	111.34	31	1	28,696	320	0	24,644,110
Nov-99	26,161,317	413	0	112.01	30	1	28,717	352	0	25,771,540
Dec-99	30,460,433	647	0	**112.69**	31	0	28,739	336	0	29,825,174
Jan-00	32,297,791	813	0	113.21	31	0	28,760	320	0	31,880,657
Feb-00	28,962,542	644	0	113.73	29	0	28,781	336	0	28,806,047
Mar-00	27,326,994	481	0	114.25	31	1	28,802	368	0	27,430,886
Apr-00	24,385,732	375	0	114.77	30	1	28,824	304	0	25,107,802
May-00	23,452,597	163	16	115.30	31	1	28,845	352	0	23,884,628
Jun-00	23,125,355	62	25	115.83	30	0	28,866	352	0	23,036,665
Jul-00	23,401,608	22	45	116.36	31	0	28,887	320	0	23,604,578
Aug-00	24,662,260	33	49	116.90	31	0	28,909	352	0	24,197,405
Sep-00	23,497,840	131	20	117.43	30	1	28,930	320	0	23,025,023
Oct-00	24,588,140	262	0	117.97	31	1	28,951	336	0	24,603,452
Nov-00	27,069,885	486	0	118.52	30	1	28,972	352	0	27,126,977
Dec-00	32,354,228	846	0	**119.06**	31	0	28,994	304	0	32,573,566

	Purchased (including transmission losses)	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Population	Number of Peak Hours	Blackout Flag	**Predicted Purchases**
Jan-01	32,002,036	757	0	119.23	31	0	29,015	352	0	**31,800,699**
Feb-01	28,987,688	682	0	119.40	28	0	29,036	320	0	**29,052,183**
Mar-01	29,723,466	631	0	119.58	31	1	29,057	352	0	**29,635,659**
Apr-01	24,792,868	342	0	119.75	30	1	29,079	320	0	**25,173,586**
May-01	23,532,606	132	8	119.92	31	1	29,100	352	0	**23,563,047**
Jun-01	24,436,311	43	57	120.10	30	0	**29,121**	336	0	**24,264,510**
Jul-01	24,327,148	27	73	120.27	31	0	29,140	336	0	**25,248,010**
Aug-01	26,276,826	2	120	120.45	31	0	29,159	352	0	**26,871,677**
Sep-01	23,127,172	112	19	120.62	30	1	29,178	304	0	**22,957,937**
Oct-01	24,927,264	272	0	120.80	31	1	29,197	352	0	**25,159,426**
Nov-01	25,697,582	366	0	120.97	30	1	29,216	352	0	**25,871,722**
Dec-01	28,565,690	554	0	**121.15**	31	0	29,235	304	0	**29,087,285**
Jan-02	30,477,490	645	0	121.50	31	0	29,254	352	0	**30,629,314**
Feb-02	28,041,532	623	0	121.86	28	0	29,273	320	0	**28,576,797**
Mar-02	29,565,474	611	0	122.22	31	1	29,292	320	0	**29,438,694**
Apr-02	25,723,552	369	7	122.59	30	1	29,311	352	0	**26,313,563**
May-02	24,784,388	242	5	122.95	31	1	29,330	352	0	**25,136,027**
Jun-02	24,555,647	52	55	123.31	30	0	29,349	320	0	**24,505,867**
Jul-02	27,860,888	3	144	123.68	31	0	29,368	352	0	**28,122,611**
Aug-02	26,778,294	9	86	124.04	31	0	29,387	336	0	**25,856,603**
Sep-02	24,912,966	40	58	124.41	30	1	29,406	320	0	**23,978,830**
Oct-02	26,115,846	336	7	124.78	31	1	29,424	352	0	**26,567,645**
Nov-02	27,928,532	501	0	125.14	30	1	29,443	336	0	**27,832,076**
Dec-02	31,114,245	681	0	**125.51**	31	0	29,462	320	0	**31,162,818**
Jan-03	34,073,030	898	0	125.66	31	0	29,481	352	0	**34,230,866**
Feb-03	30,698,615	781	0	125.81	28	0	29,500	320	0	**30,941,569**
Mar-03	30,269,473	633	0	125.95	31	1	29,519	336	0	**30,154,895**
Apr-03	26,583,794	419	0	126.10	30	1	29,538	336	0	**26,896,502**
May-03	23,994,002	188	0	126.24	31	1	29,557	336	0	**24,438,889**
Jun-03	24,222,171	46	42	126.39	30	0	29,576	336	0	**24,326,785**
Jul-03	25,872,223	5	77	126.54	31	0	29,595	352	0	**25,801,202**
Aug-03	24,315,869	8	103	126.68	31	0	29,614	320	1	**24,315,869**
Sep-03	23,433,555	66	11	126.83	30	1	29,633	336	0	**22,837,560**
Oct-03	25,678,835	305	0	126.98	31	1	29,652	352	0	**26,180,916**
Nov-03	27,201,096	439	0	127.12	30	1	29,671	320	0	**27,168,871**
Dec-03	30,416,074	631	0	**127.27**	31	0	29,690	336	0	**30,906,321**
Jan-04	34,930,219	950	0	127.53	31	0	29,709	336	0	**35,048,247**
Feb-04	29,994,639	684	0	127.80	29	0	29,728	320	0	**30,476,089**
Mar-04	29,562,626	559	0	128.06	31	1	29,747	368	0	**29,700,226**
Apr-04	25,637,793	360	0	128.32	30	1	29,766	336	0	**26,399,741**
May-04	24,329,404	188	9	128.59	31	1	29,785	320	0	**24,931,094**
Jun-04	23,822,704	59	26	128.85	30	0	29,804	352	0	**24,240,041**
Jul-04	25,281,709	8	72	129.12	31	0	29,823	336	0	**25,836,082**
Aug-04	24,966,201	14	32	129.38	31	0	29,842	336	0	**24,371,933**
Sep-04	24,347,914	49	28	129.65	30	1	29,861	336	0	**23,594,110**
Oct-04	25,098,899	266	0	129.92	31	1	29,880	320	0	**25,728,205**
Nov-04	28,159,682	435	0	130.19	30	1	29,899	352	0	**27,651,963**
Dec-04	33,451,268	743	0	**130.45**	31	0	29,918	336	0	**32,642,774**
Jan-05	35,565,108	849	0	130.74	31	0	29,937	320	0	**33,927,052**
Feb-05	30,518,799	672	0	131.03	28	0	29,956	320	0	**30,086,890**
Mar-05	31,447,259	651	0	131.33	31	1	29,975	352	0	**31,074,871**
Apr-05	26,261,931	339	0	131.62	30	1	29,993	336	0	**26,418,147**
May-05	25,062,171	203	0	131.91	31	1	30,012	336	0	**25,213,681**
Jun-05	27,667,588	15	110	132.20	30	0	30,031	352	0	**27,268,982**
Jul-05	28,823,089	1	153	132.50	31	0	30,050	320	0	**29,082,632**
Aug-05	28,281,114	2	105	132.79	31	0	30,069	352	0	**27,473,448**
Sep-05	25,701,134	49	38	133.09	30	1	30,088	336	0	**24,301,953**
Oct-05	26,314,163	248	6	133.38	31	1	30,107	320	0	**26,041,277**
Nov-05	28,549,590	448	0	133.68	30	1	30,126	352	0	**28,129,639**
Dec-05	32,730,996	713	0	**133.98**	31	0	30,145	320	0	**32,448,118**
Jan-06	32,654,590	646	0	134.25	31	0	30,164	336	0	**31,724,032**
Feb-06	30,394,010	696	0	134.53	28	0	30,183	320	0	**30,705,536**
Mar-06	31,527,428	605	0	134.81	31	1	30,202	368	0	**30,902,498**
Apr-06	26,030,174	326	0	135.08	30	1	30,221	304	0	**26,329,707**
May-06	25,698,244	155	19	135.36	31	1	30,240	352	0	**25,752,868**
Jun-06	26,584,814	33	65	135.64	30	0	**30,259**	352	0	**26,040,001**
Jul-06	29,413,449	3	144	135.92	31	0	30,278	320	0	**29,055,463**
Aug-06	27,807,703	12	77	136.20	31	0	30,297	352	0	**26,835,608**
Sep-06	24,611,987	128	4	136.48	30	1	30,316	320	0	**24,171,808**

	Purchased (including transmission losses)	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Population	Number of Peak Hours	Blackout Flag	**Predicted Purchases**	
Oct-06	26,917,051	310	0	136.76	31	1	30,335	336	0	**27,032,119**	
Nov-06	28,097,117	406	0	137.04	30	1	30,354	352	0	**27,893,929**	
Dec-06	30,100,094	560	0	**137.33**	31	0	30,373	304	0	**30,666,280**	
Jan-07	32,869,611	779	0	137.57	31	0	30,392	352	0	**33,859,195**	
Feb-07	31,402,320	801	0	137.82	28	0	30,411	320	0	**32,371,371**	
Mar-07	30,908,220	593	0	138.07	31	1	30,430	352	0	**30,923,394**	
Apr-07	26,653,109	381	2	138.33	30	1	30,449	320	0	**27,535,083**	
May-07	25,174,872	77	1	138.58	31	1	30,468	352	0	**24,348,273**	
Jun-07	26,613,989	35	79	138.83	30	0	30,487	336	0	**26,812,653**	
Jul-07	26,717,129	12	72	139.08	31	0	30,506	336	0	**26,789,601**	
Aug-07	27,900,949	19	85	139.33	31	0	30,525	352	0	**27,534,608**	
Sep-07	24,998,480	59	28	139.59	30	1	30,544	304	0	**24,408,288**	
Oct-07	25,979,840	164	4	139.84	31	1	30,562	352	0	**25,713,158**	
Nov-07	28,705,533	499	0	140.09	30	1	30,581	352	0	**29,390,161**	
Dec-07	32,426,863	687	0	**140.35**	31	0	30,600	304	0	**32,592,345**	
Jan-08	32,784,593	709	0	140.30	31	0	30,619	352	0	**33,237,006**	
Feb-08	30,859,005	702	0	140.25	29	0	30,638	320	0	**31,894,593**	
Mar-08	31,264,871	559	0	140.21	31	1	30,657	304	0	**30,404,756**	
Apr-08	26,069,763	264	1	140.16	30	1	30,676	352	0	**26,471,169**	
May-08	24,996,489	216	1	140.11	31	1	30,695	336	0	**26,272,879**	
Jun-08	25,726,372	36	52	140.07	30	0	30,714	336	0	**26,026,661**	
Jul-08	27,722,067	4	78	140.02	31	0	30,733	352	0	**27,287,682**	
Aug-08	26,562,381	20	31	139.97	31	0	30,752	320	0	**25,431,625**	
Sep-08	24,843,728	84	14	139.93	30	1	30,771	336	0	**24,603,731**	
Oct-08	25,997,355	298	1	139.88	31	1	30,790	352	0	**27,512,932**	
Nov-08	27,977,163	444	0	139.83	30	1	30,809	304	0	**28,532,740**	
Dec-08	32,538,425	594	0	**139.79**	31	0	30,828	336	0	**31,826,715**	
Jan-08	32,784,593	791	0	140.30	31	0	30,619	352	0	**34,297,918**	Weather Normal
Feb-08	30,859,005	675	0	140.25	29	0	30,638	320	0	**31,544,967**	Weather Normal
Mar-08	31,264,871	595	0	140.21	31	1	30,657	304	0	**30,873,443**	Weather Normal
Apr-08	26,069,763	361	1	140.16	30	1	30,676	352	0	**27,719,466**	Weather Normal
May-08	24,996,489	169	7	140.11	31	1	30,695	336	0	**25,916,349**	Weather Normal
Jun-08	25,726,372	40	56	140.07	30	0	30,714	336	0	**26,215,622**	Weather Normal
Jul-08	27,722,067	9	92	140.02	31	0	30,733	352	0	**27,888,127**	Weather Normal
Aug-08	26,562,381	13	70	139.97	31	0	30,752	320	0	**26,874,564**	Weather Normal
Sep-08	24,843,728	79	24	139.93	30	1	30,771	336	0	**24,941,174**	Weather Normal
Oct-08	25,997,355	277	1	139.88	31	1	30,790	352	0	**27,279,238**	Weather Normal
Nov-08	27,977,163	455	0	139.83	30	1	30,809	304	0	**28,677,564**	Weather Normal
Dec-08	32,538,425	655	0	139.79	31	0	30,828	336	0	**32,605,340**	Weather Normal
Jan-09										**32,926,001**	-4.00%
Feb-09										**30,283,169**	-4.00%
Mar-09										**29,638,505**	-4.00%
Apr-09										**26,610,687**	-4.00%
May-09										**24,879,695**	-4.00%
Jun-09										**25,166,997**	-4.00%
Jul-09										**26,772,602**	-4.00%
Aug-09										**25,799,582**	-4.00%
Sep-09										**23,943,527**	-4.00%
Oct-09										**26,188,069**	-4.00%
Nov-09										**27,530,461**	-4.00%
Dec-09										**31,301,127**	-4.00%
Jan-10										**32,827,223**	-0.30%
Feb-10										**30,192,319**	-0.30%
Mar-10										**29,549,590**	-0.30%
Apr-10										**26,530,855**	-0.30%
May-10										**24,805,056**	-0.30%
Jun-10										**25,091,496**	-0.30%
Jul-10										**26,692,284**	-0.30%
Aug-10										**25,722,183**	-0.30%
Sep-10										**23,871,697**	-0.30%
Oct-10										**26,109,504**	-0.30%
Nov-10										**27,447,870**	-0.30%
Dec-10										**31,207,223**	-0.30%

APPENDIX 3 – C

OPDC's Summary and analysis of rate change impacts on core distribution revenues follows on the next eight pages.

Appendix 3-C: Summary of Rate Impacts On OPDC Core Distribution Revenues From 2004 Through 2009

SUMMARY	2003	2004	2005	2006	2007	2008	2009
Distribution Revenues reported on FS	6,979,000	6,763,000	6,667,000	6,387,000	6,201,000	6,241,000	6,178,000
Unbilled adjustments and SSS Admin	66,000	113,000	(4,000)	(40,000)	(8,000)	57,000	33,000
Core Revenues - All Classes Billed	**6,913,000**	**6,650,000**	**6,671,000**	**6,427,000**	**6,209,000**	**6,184,000**	**6,145,000**
[B] Core revenues billed variance		(263,000)	21,000	(244,000)	(218,000)	(25,000)	(39,000)
Percentage Change		**-3.8%**	**0.3%**	**-3.7%**	**-3.4%**	**-0.4%**	**-0.6%**
[E] Rate variance based on prior year volumes		**($244,000)**	**$71,000**	**($606,000)**	**$54,000**	**($10,000)**	**$9,000**
Percentage of rate variance to revenues		**-3.5%**	**1.1%**	**-9.1%**	**0.8%**	**-0.2%**	**0.1%**

Billing Determinants

	2003	2004	2005	2006	2007	2008	2009
Customer count	12,074	12,187	12,300	12,483	12,607	12,720	12,802
Consumption	158,219,903	159,547,694	162,751,196	159,167,335	159,700,026	159,974,643	157,101,900
Demand kw	433,287	400,119	413,922	416,183	417,532	404,841	409,304
Transformer discount kw	274,834	243,772	253,485	249,723	246,980	236,135	239,700

VARIANCE SUMMARY

	2004	2005	2006	2007	2008	2009
[E] Rate variance based on prior year volumes	**($244,000)**	**$71,000**	**($606,000)**	**$54,000**	**($10,000)**	**$9,000**
[F] Volume variance = [D] - [E]	($31,000)	$87,000	$5,000	$33,000	($30,000)	($2,000)
[G] Variance due to other *	$12,000	($137,000)	$357,000	($305,000)	$15,000	($46,000)
[B] Core revenues billed variance	**($263,000)**	**$21,000**	**($244,000)**	**($218,000)**	**($25,000)**	**($39,000)**

*** Other: Rates become effective May 1 so full impact of rate change is dampened in any particular year. Also included in this category would be the change in rates applied to volume differences between years.**

RESIDENTIAL	2003	2004	2005	2006	2007	2008	2009
Core Distribution Rates - effective:	1-Dec-02	1-Apr-04	1-Apr-05	1-May-06	1-May-07	1-May-08	1-May-09
Monthly Service Charge	$16.60	$16.60	$14.34	$13.20	$13.32	$13.31	$13.34
Distribution Volumetric Charge	$0.01090	$0.0098	$0.0131	$0.0120	$0.0121	$0.0121	$0.0121
Change in rates - for rate variance							
Monthly Service Charge		$0.00	-$2.26	-$1.14	$0.12	-$0.01	$0.03
Distribution Volumetric Charge		-$0.0011	$0.0033	-$0.0011	$0.0001	$0.0000	$0.0000
Billing Determinants							
Customer count	10,595	10,695	10,786	10,943	11,061	11,181	11,295
Customers billed x 12	127,140	128,340	129,432	131,316	132,732	134,172	135,540
Total kwh Consumption	108,163,534	108,386,794	110,976,692	108,206,276	109,560,116	109,814,584	108,037,105
Core Distribution Revenues Actual Billed							
[A] Core revenues actual billed	**3,381,163**	**3,261,040**	**3,282,404**	**3,179,550**	**3,114,999**	**3,134,998**	**3,113,565**
[B] Core revenues billed variance		**(120,123)**	**21,364**	**(102,854)**	**(64,551)**	**19,999**	**(21,433)**
Pro Forma Core Distribution Revenues - Actual Volumes Multiplied by Rate as if in effect from beginning of year							
Monthly Service Charge	$2,110,520	$2,130,440	$1,856,050	$1,733,370	$1,767,990	$1,785,830	$1,808,100
Distribution Volumetric Charge	$1,178,980	$1,062,190	$1,453,790	$1,298,480	$1,325,680	$1,328,760	$1,307,250
[C] Pro forma revenues	**$3,289,500**	**$3,192,630**	**$3,309,840**	**$3,031,850**	**$3,093,670**	**$3,114,590**	**$3,115,350**
Pro Forma Revenue Variance							
Monthly Service Charge		$19,920	($274,390)	($122,680)	$34,620	$17,840	$22,270
Distribution Volumetric Charge		($116,790)	$391,600	($155,310)	$27,200	$3,080	($21,510)
[D] Pro Forma revenue variance		**($96,870)**	**$117,210**	**($277,990)**	**$61,820**	**$20,920**	**$760**
Rate variance (applied to previous years volumes)							
Monthly Service Charge		$0	($290,048)	($147,552)	$15,758	($1,327)	$4,025
Distribution Volumetric Charge		($118,980)	$357,676	($122,074)	$10,821	$0	$0
[E] Rate variance based on prior year volumes		**($118,980)**	**$67,628**	**($269,627)**	**$26,579**	**($1,327)**	**$4,025**
Volume variance (assumed to be difference between [D] -[E])							
Monthly Service Charge		$19,920	$15,658	$24,872	$18,862	$19,167	$18,245
Distribution Volumetric Charge		$2,190	$33,924	($33,236)	$16,379	$3,080	($21,510)
[F] Volume variance = [D] - [E]		**$22,110**	**$49,582**	**($8,363)**	**$35,241**	**$22,247**	**($3,265)**
Variance due to rate implementation April / May 1 and other volume effects							
[B] Core revenues billed variance		($120,123)	$21,364	($102,854)	($64,551)	$19,999	($21,433)
[D] Pro Forma revenue variance		($96,870)	$117,210	($277,990)	$61,820	$20,920	$760
[G] Variance due to other		**($23,253)**	**($95,846)**	**$175,136**	**($126,371)**	**($921)**	**($22,193)**

VARIANCE SUMMARY						
[E] Rate variance based on prior year volumes	($118,980)	$67,628	($269,627)	$26,579	($1,327)	$4,025
[F] Volume variance = [D] - [E]	$22,110	$49,582	($8,363)	$35,241	$22,247	($3,265)
[G] Variance due to other	($23,253)	($95,846)	$175,136	($126,371)	($921)	($22,193)
[B] Core revenues billed variance	**($120,123)**	**$21,364**	**($102,854)**	**($64,551)**	**$19,999**	**($21,433)**

GS <= TO 50 KW	2003	2004	2005	2006	2007	2008	2009
Core Distribution Rates - effective:	1-Dec-02	1-Apr-04	1-Apr-05	1-May-06	1-May-07	1-May-08	1-May-09
Monthly Service Charge	$39.68	$39.68	$33.55	$30.49	$30.76	$30.73	$30.79
Distribution Volumetric Charge	$0.01380	$0.0121	$0.0149	$0.0136	$0.0137	$0.0137	$0.0137
Change in rates - for rate variance							
Monthly Service Charge		$0.00	-$6.13	-$3.06	$0.27	-$0.03	$0.06
Distribution Volumetric Charge		-$0.0017	$0.0028	-$0.0013	$0.0001	$0.0000	$0.0000
Billing Determinants							
Customer count	1,278	1,289	1,315	1,339	1,344	1,347	1,351
Customers billed x 12	15,336	15,468	15,780	16,068	16,128	16,164	16,212
Total kwh Consumption	48,794,159	49,824,701	50,366,915	49,863,299	49,217,302	49,297,751	48,222,530

	2003	2004	2005	2006	2007	2008	2009
Core Distribution Revenues Actual Billed							
[A] Core revenues actual billed	**1,313,235**	**1,250,680**	**1,262,448**	**1,228,278**	**1,176,540**	**1,180,391**	**1,159,384**
[B] Core revenues billed variance		**(62,555)**	**11,768**	**(34,170)**	**(51,738)**	**3,851**	**(21,007)**
Pro Forma Core Distribution Revenues - Actual Volumes Multiplied by Rate as if in effect from beginning of year							
Monthly Service Charge	$608,530	$613,770	$529,420	$489,910	$496,100	$496,720	$499,170
Distribution Volumetric Charge	$673,360	$602,880	$750,470	$678,140	$674,280	$675,380	$660,650
[C] Pro forma revenues	**$1,281,890**	**$1,216,650**	**$1,279,890**	**$1,168,050**	**$1,170,380**	**$1,172,100**	**$1,159,820**
Pro Forma Revenue Variance							
Monthly Service Charge		$5,240	($84,350)	($39,510)	$6,190	$620	$2,450
Distribution Volumetric Charge		($70,480)	$147,590	($72,330)	($3,860)	$1,100	($14,730)
[D] Pro Forma revenue variance		**($65,240)**	**$63,240**	**($111,840)**	**$2,330**	**$1,720**	**($12,280)**
Rate variance (applied to previous years volumes)							
Monthly Service Charge		$0	($94,819)	($48,287)	$4,338	($484)	$970
Distribution Volumetric Charge		($82,950)	$139,509	($65,477)	$4,986	$0	$0
[E] Rate variance based on prior year volumes		**($82,950)**	**$44,690**	**($113,764)**	**$9,325**	**($484)**	**$970**
Volume variance (assumed to be difference between [D] -[E])							
Monthly Service Charge		$5,240	$10,469	$8,777	$1,852	$1,104	$1,480
Distribution Volumetric Charge		$12,470	$8,081	($6,853)	($8,846)	$1,100	($14,730)
[F] Volume variance = [D] - [E]		**$17,710**	**$18,550**	**$1,924**	**($6,995)**	**$2,204**	**($13,250)**
Variance due to rate implementation April / May 1 and other volume effects							
[B] Core revenues billed variance		($62,555)	$11,768	($34,170)	($51,738)	$3,851	($21,007)
[D] Pro Forma revenue variance		($65,240)	$63,240	($111,840)	$2,330	$1,720	($12,280)
[G] Variance due to other		**$2,685**	**($51,472)**	**$77,670**	**($54,068)**	**$2,131**	**($8,727)**

VARIANCE SUMMARY	2003	2004	2005	2006	2007	2008	2009
[E] Rate variance based on prior year volumes		($82,950)	$44,690	($113,764)	$9,325	($484)	$970
[F] Volume variance = [D] - [E]		$17,710	$18,550	$1,924	($6,995)	$2,204	($13,250)
[G] Variance due to other		$2,685	($51,472)	$77,670	($54,068)	$2,131	($8,727)
[B] Core revenues billed variance		**($62,555)**	**$11,768**	**($34,170)**	**($51,738)**	**$3,851**	**($21,007)**

GS > 50 KW Non TOU	2003	2004	2005	2006	2007	2008	2009
Core Distribution Rates - effective:	1-Dec-02	1-Apr-04	1-Apr-05	1-May-06	1-May-07	1-May-08	1-May-09
Monthly Service Charge	$394.60	$394.60	$337.27	$334.70	$337.71	$337.37	$338.04
Distribution Volumetric Charge	$4.42640	$4.3033	$4.5546	$3.0910	$3.1188	$3.1157	$3.1219
Transformer Discount	-$0.60000	-$0.60000	-$0.60000	-$0.60000	-$0.60000	-$0.60000	-$0.60000
Change in rates - for rate variance							
Monthly Service Charge		$0.00	-$57.33	-$2.57	$3.01	-$0.34	$0.67
Distribution Volumetric Charge		-$0.1231	$0.2513	-$1.4636	$0.0278	-$0.0031	$0.0062
Billing Determinants							
Customer count	150	152	148	151	153	148	149
Customers billed x 12	1,800	1,824	1,776	1,812	1,836	1,776	1,788
Demand kw	281,151	259,833	266,182	273,791	278,742	267,858	271,489
Transformer Discount kW	229,250	198,188	207,901	116,019	112,927	107,452	109,900

	2003	2004	2005	2006	2007	2008	2009
Core Distribution Revenues Actual Billed							
[A] Core revenues actual billed	**1,763,591**	**1,689,144**	**1,691,773**	**1,570,662**	**1,422,881**	**1,382,346**	**1,391,132**
[B] Core revenues billed variance		**(74,447)**	**2,629**	**(121,111)**	**(147,781)**	**(40,535)**	**8,786**
Pro Forma Core Distribution Revenues - Actual Volumes Multiplied by Rate as if in effect from beginning of year							
Monthly Service Charge	$710,280	$719,750	$598,990	$606,480	$620,040	$599,170	$604,420
Distribution Volumetric Charge	$1,244,490	$1,118,140	$1,212,350	$846,290	$869,340	$834,570	$847,570
Transformer Discount Credit	(137,550)	(118,910)	(124,740)	(69,610)	(67,760)	(64,470)	(65,940)
[C] Pro forma revenues	**$1,817,220**	**$1,718,980**	**$1,686,600**	**$1,383,160**	**$1,421,620**	**$1,369,270**	**$1,386,050**
Pro Forma Revenue Variance							
Monthly Service Charge		$9,470	($120,760)	$7,490	$13,560	($20,870)	$5,250
Distribution Volumetric Charge		($126,350)	$94,210	($366,060)	$23,050	($34,770)	$13,000
Transformer Discount Credit		$18,640	($5,830)	$55,130	$1,850	$3,290	($1,470)
[D] Pro Forma revenue variance		**($98,240)**	**($32,380)**	**($303,440)**	**$38,460**	**($52,350)**	**$16,780**
Rate variance (applied to previous years volumes)							
Monthly Service Charge		$0	($104,570)	($4,564)	$5,454	($624)	$1,190
Distribution Volumetric Charge		($34,610)	$65,296	($389,584)	$7,611	($864)	$1,672
[E] Rate variance based on prior year volumes		**($34,610)**	**($39,274)**	**($394,148)**	**$13,066**	**($1,488)**	**$2,861**
Volume variance (assumed to be difference between [D] -[E])							
Monthly Service Charge		$9,470	($16,190)	$12,054	$8,106	($20,246)	$4,060
Distribution Volumetric Charge		($91,740)	$28,914	$23,524	$15,439	($33,906)	$11,328
Transformer Discount Credit		$18,640	($5,830)	$55,130	$1,850	$3,290	($1,470)
[F] Volume variance = [D] - [E]		**($63,630)**	**$6,894**	**$90,708**	**$25,394**	**($50,862)**	**$13,919**
Variance due to rate implementation April / May 1 and other volume effects							
[B] Core revenues billed variance		($74,447)	$2,629	($121,111)	($147,781)	($40,535)	$8,786
[D] Pro Forma revenue variance		($98,240)	($32,380)	($303,440)	$38,460	($52,350)	$16,780
[G] Variance due to other		**$23,793**	**$35,009**	**$182,329**	**($186,241)**	**$11,815**	**($7,994)**

VARIANCE SUMMARY	2004	2005	2006	2007	2008	2009
[E] Rate variance based on prior year volumes	($34,610)	($39,274)	($394,148)	$13,066	($1,488)	$2,861
[F] Volume variance = [D] - [E]	($63,630)	$6,894	$90,708	$25,394	($50,862)	$13,919
[G] Variance due to other	$23,793	$35,009	$182,329	($186,241)	$11,815	($7,994)
[B] Core revenues billed variance	**($74,447)**	**$2,629**	**($121,111)**	**($147,781)**	**($40,535)**	**$8,786**

GS > 50 KW Formerly TOU	2003	2004	2005	2006	2007	2008	2009
Core Distribution Rates - effective:	1-Dec-02	1-Apr-04	1-Apr-05	1-May-06	1-May-07	1-May-08	1-May-09
Monthly Service Charge	$758.00	$758.00	$681.92	$334.70	$337.71	$337.37	$338.04
Distribution Volumetric Charge	$1.22140	$1.2086	$1.3117	$3.1406	$3.1688	$3.1157	$3.1219
Transformer Discount	-$0.60000	-$0.60000	-$0.60000	-$0.60000	-$0.60000	-$0.60000	-$0.60000
Change in rates - for rate variance							
Monthly Service Charge		$0.00	-$76.08	-$347.22	$3.01	-$0.34	$0.67
Distribution Volumetric Charge		-$0.0128	$0.1031	$1.8289	$0.0282	-$0.0531	$0.0062
Billing Determinants							
Customer count	7	7	7	7	7	7	7
Customers billed x 12	84	84	84	84	84	84	84
Demand kw	143,779	132,007	139,496	134,152	130,685	128,920	129,800
Transformer Discount kW	45,584	45,584	45,584	133,704	134,053	128,683	129,800
Core Distribution Revenues Actual Billed							
[A] Core revenues actual billed	**258,586**	**243,308**	**228,447**	**292,902**	**366,244**	**358,646**	**355,383**
[B] Core revenues billed variance		**(15,278)**	**(14,861)**	**64,455**	**73,342**	**(7,598)**	**(3,263)**
Pro Forma Core Distribution Revenues - Actual Volumes Multiplied by Rate as if in effect from beginning of year							
Monthly Service Charge	$63,670	$63,670	$57,280	$28,110	$28,370	$28,340	$28,400
Distribution Volumetric Charge	$175,610	$159,540	$182,980	$421,320	$414,110	$401,680	$405,230
Transformer Discount Credit	(27,350)	(27,350)	(27,350)	(80,220)	(80,430)	(77,210)	(77,880)
[C] Pro forma revenues	**$211,930**	**$195,860**	**$212,910**	**$369,210**	**$362,050**	**$352,810**	**$355,750**
Pro Forma Revenue Variance							
Monthly Service Charge		$0	($6,390)	($29,170)	$260	($30)	$60
Distribution Volumetric Charge		($16,070)	$23,440	$238,340	($7,210)	($12,430)	$3,550
Transformer Discount Credit		$0	$0	($52,870)	($210)	$3,220	($670)
[D] Pro Forma revenue variance		**($16,070)**	**$17,050**	**$156,300**	**($7,160)**	**($9,240)**	**$2,940**
Rate variance (applied to previous years volumes)							
Monthly Service Charge		$0	($6,391)	($29,166)	$253	($29)	$56
Distribution Volumetric Charge		($1,840)	$13,610	$255,124	$3,783	($6,939)	$805
[E] Rate variance based on prior year volumes		**($1,840)**	**$7,219**	**$225,958**	**$4,036**	**($6,968)**	**$861**
Volume variance (assumed to be difference between [D] -[E])							
Monthly Service Charge		$0	$1	($4)	$7	($1)	$4
Distribution Volumetric Charge		($14,230)	$9,830	($16,784)	($10,993)	($5,491)	$2,745
Transformer Discount Credit		$0	$0	($52,870)	($210)	$3,220	($670)
[F] Volume variance = [D] - [E]		**($14,230)**	**$9,831**	**($69,658)**	**($11,196)**	**($2,272)**	**$2,079**
Variance due to rate implementation April / May 1 and other volume effects							
[B] Core revenues billed variance		($15,278)	($14,861)	$64,455	$73,342	($7,598)	($3,263)
[D] Pro Forma revenue variance		($16,070)	$17,050	$156,300	($7,160)	($9,240)	$2,940
[G] Variance due to other		**$792**	**($31,911)**	**($91,845)**	**$80,502**	**$1,642**	**($6,203)**
VARIANCE SUMMARY							
[E] Rate variance based on prior year volumes		($1,840)	$7,219	$225,958	$4,036	($6,968)	$861
[F] Volume variance = [D] - [E]		($14,230)	$9,831	($69,658)	($11,196)	($2,272)	$2,079
[G] Variance due to other		$792	($31,911)	($91,845)	$80,502	$1,642	($6,203)
[B] Core revenues billed variance		**($15,278)**	**($14,861)**	**$64,455**	**$73,342**	**($7,598)**	**($3,263)**

UNMETERED SCATTERED LOAD	2003	2004	2005	2006	2007	2008	2009
Core Distribution Rates - effective:	1-Dec-02	1-Apr-04	1-Apr-05	1-May-06	1-May-07	1-May-08	1-May-09
Monthly Service Charge	$39.68	$39.68	$33.55	$15.24	$15.38	$15.36	$15.39
Distribution Volumetric Charge	$0.01380	$0.0121	$0.0149	$0.0137	$0.0138	$0.0138	$0.0138
Change in rates - for rate variance							
Monthly Service Charge		$0.00	-$6.13	-$18.31	$0.14	-$0.02	$0.03
Distribution Volumetric Charge		-$0.0017	$0.0028	-$0.0012	$0.0001	$0.0000	$0.0000
Billing Determinants							
Connections x12	2,244	2,400	2,472	2,184	1,872	1,860	1,836
Total kwh Consumption	1,262,210	1,336,199	1,407,589	1,097,760	922,608	862,308	842,265
Core Distribution Revenues Actual Billed							
[A] Core revenues actual billed	**102,336**	**118,427**	**110,569**	**63,633**	**41,655**	**41,033**	**39,856**
[B] Core revenues billed variance		**16,091**	**(7,858)**	**(46,936)**	**(21,978)**	**(622)**	**(1,177)**
Pro Forma Core Distribution Revenues - Actual Volumes Multiplied by Rate as if in effect from beginning of year							
Monthly Service Charge	$89,040	$95,230	$82,940	$33,280	$28,790	$28,570	$28,260
Distribution Volumetric Charge	$17,420	$16,170	$20,970	$15,040	$12,730	$11,900	$11,620
[C] Pro forma revenues	**$106,460**	**$111,400**	**$103,910**	**$48,320**	**$41,520**	**$40,470**	**$39,880**
Pro Forma Revenue Variance							
Monthly Service Charge		$6,190	($12,290)	($49,660)	($4,490)	($220)	($310)
Distribution Volumetric Charge		($1,250)	$4,800	($5,930)	($2,310)	($830)	($280)
[D] Pro Forma revenue variance		**$4,940**	**($7,490)**	**($55,590)**	**($6,800)**	**($1,050)**	**($590)**
Rate variance (applied to previous years volumes)							
Monthly Service Charge		$0	($14,712)	($45,262)	$306	($37)	$56
Distribution Volumetric Charge		($2,146)	$3,741	($1,689)	$110	$0	$0
[E] Rate variance based on prior year volumes		**($2,146)**	**($10,971)**	**($46,951)**	**$416**	**($37)**	**$56**
Volume variance (assumed to be difference between [D] -[E])							
Monthly Service Charge		$6,190	$2,422	($4,398)	($4,796)	($183)	($366)
Distribution Volumetric Charge		$896	$1,059	($4,241)	($2,420)	($830)	($280)
[F] Volume variance = [D] - [E]		**$7,086**	**$3,481**	**($8,639)**	**($7,216)**	**($1,013)**	**($646)**
Variance due to rate implementation April / May 1 and other volume effects							
[B] Core revenues billed variance		$16,091	($7,858)	($46,936)	($21,978)	($622)	($1,177)
[D] Pro Forma revenue variance		$4,940	($7,490)	($55,590)	($6,800)	($1,050)	($590)
[G] Variance due to other		**$11,151**	**($368)**	**$8,654**	**($15,178)**	**$428**	**($587)**

VARIANCE SUMMARY							
[E] Rate variance based on prior year volumes		($2,146)	($10,971)	($46,951)	$416	($37)	$56
[F] Volume variance = [D] - [E]		$7,086	$3,481	($8,639)	($7,216)	($1,013)	($646)
[G] Variance due to other		$11,151	($368)	$8,654	($15,178)	$428	($587)
[B] Core revenues billed variance		**$16,091**	**($7,858)**	**($46,936)**	**($21,978)**	**($622)**	**($1,177)**

SENTINEL LIGHTING	2003	2004	2005	2006	2007	2008	2009
Core Distribution Rates - effective:	1-Dec-02	1-Apr-04	1-Apr-05	1-May-06	1-May-07	1-May-08	1-May-09
Monthly Service Charge (per connection)	$4.07	$4.07	$3.32	$3.15	$3.18	$3.18	$3.19
Distribution Volumetric Charge	$7.99100	$6.7722	$8.7067	$8.2665	$8.3409	$8.3326	$8.3493
Change in rates - for rate variance							
Monthly Service Charge		$0.00	-$0.75	-$0.17	$0.03	$0.00	$0.01
Distribution Volumetric Charge		-$1.2188	$1.9345	-$0.4402	$0.0744	-$0.0083	$0.0167
Billing Determinants							
Connections	278	273	260	244	212	206	200
Connections x12	3,336	3,276	3,120	2,928	2,544	2,472	2,400
Demand kw	1,376	1,273	1,208	1,195	1,029	979	933
Core Distribution Revenues Actual Billed							
[A] Core revenues actual billed	**18,523**	**12,451**	**20,422**	**19,954**	**16,805**	**16,000**	**15,429**
[B] Core revenues billed variance		**(6,072)**	**7,971**	**(468)**	**(3,149)**	**(805)**	**(571)**
Pro Forma Core Distribution Revenues - Actual Volumes Multiplied by Rate as if in effect from beginning of year							
Monthly Service Charge	$13,580	$13,330	$10,360	$9,220	$8,090	$7,860	$7,660
Distribution Volumetric Charge	$11,000	$8,620	$10,520	$9,880	$8,580	$8,160	$7,790
[C] Pro forma revenues	**$24,580**	**$21,950**	**$20,880**	**$19,100**	**$16,670**	**$16,020**	**$15,450**
Pro Forma Revenue Variance							
Monthly Service Charge		($250)	($2,970)	($1,140)	($1,130)	($230)	($200)
Distribution Volumetric Charge		($2,380)	$1,900	($640)	($1,300)	($420)	($370)
[D] Pro Forma revenue variance		**($2,630)**	**($1,070)**	**($1,780)**	**($2,430)**	**($650)**	**($570)**
Rate variance (applied to previous years volumes)							
Monthly Service Charge		$0	($2,457)	($530)	$88	$0	$25
Distribution Volumetric Charge		($1,677)	$2,463	($532)	$89	($9)	$16
[E] Rate variance based on prior year volumes		**($1,677)**	**$6**	**($1,062)**	**$177**	**($9)**	**$41**
Volume variance (assumed to be difference between [D] -[E])							
Monthly Service Charge		($250)	($513)	($610)	($1,218)	($230)	($225)
Distribution Volumetric Charge		($703)	($563)	($108)	($1,389)	($411)	($386)
[F] Volume variance = [D] - [E]		**($953)**	**($1,076)**	**($718)**	**($2,607)**	**($641)**	**($611)**
Variance due to rate implementation April / May 1 and other volume effects							
[B] Core revenues billed variance		($6,072)	$7,971	($468)	($3,149)	($805)	($571)
[D] Pro Forma revenue variance		($2,630)	($1,070)	($1,780)	($2,430)	($650)	($570)
[G] Variance due to other		**($3,442)**	**$9,041**	**$1,312**	**($719)**	**($155)**	**($1)**
VARIANCE SUMMARY							
[E] Rate variance based on prior year volumes		($1,677)	$6	($1,062)	$177	($9)	$41
[F] Volume variance = [D] - [E]		($953)	($1,076)	($718)	($2,607)	($641)	($611)
[G] Variance due to other		($3,442)	$9,041	$1,312	($719)	($155)	($1)
[B] Core revenues billed variance		**($6,072)**	**$7,971**	**($468)**	**($3,149)**	**($805)**	**($571)**

STREETLIGHTING	2003	2004	2005	2006	2007	2008	2009
Core Distribution Rates - effective:	1-Dec-02	1-Apr-04	1-Apr-05	1-May-06	1-May-07	1-May-08	1-May-09
Monthly Service Charge (per connection)	$1.33	$1.33	$1.15	$1.05	$1.06	$1.06	$1.06
Distribution Volumetric Charge	$2.74480	$2.5056	$3.8402	$3.4950	$3.5265	$3.5230	$3.5300
Change in rates - for rate variance							
Monthly Service Charge		$0.00	-$0.18	-$0.10	$0.01	$0.00	$0.00
Distribution Volumetric Charge		-$0.2392	$1.3346	-$0.3452	$0.0315	-$0.0035	$0.0070
Billing Determinants							
Connections	3,460	3,483	3,490	3,494	3,512	3,526	3,541
Connections x12	41,520	41,796	41,880	41,928	42,144	42,312	42,492
Demand kw	6,981	7,006	7,036	7,045	7,076	7,084	7,082
Core Distribution Revenues Actual Billed							
[A] Core revenues actual billed	**75,044**	**74,497**	**75,195**	**72,021**	**69,979**	**70,559**	**70,021**
[B] Core revenues billed variance		**(547)**	**698**	**(3,174)**	**(2,042)**	**580**	**(538)**
Pro Forma Core Distribution Revenues - Actual Volumes Multiplied by Rate as if in effect from beginning of year							
Monthly Service Charge	$55,220	$55,590	$48,160	$44,020	$44,670	$44,850	$45,040
Distribution Volumetric Charge	$19,160	$17,550	$27,020	$24,620	$24,950	$24,960	$25,000
[C] Pro forma revenues	**$74,380**	**$73,140**	**$75,180**	**$68,640**	**$69,620**	**$69,810**	**$70,040**
Pro Forma Revenue Variance							
Monthly Service Charge		$370	($7,430)	($4,140)	$650	$180	$190
Distribution Volumetric Charge		($1,610)	$9,470	($2,400)	$330	$10	$40
[D] Pro Forma revenue variance		**($1,240)**	**$2,040**	**($6,540)**	**$980**	**$190**	**$230**
Rate variance (applied to previous years volumes)							
Monthly Service Charge		$0	($7,523)	($4,188)	$419	$0	$0
Distribution Volumetric Charge		($1,670)	$9,350	($2,429)	$222	($25)	$50
[E] Rate variance based on prior year volumes		**($1,670)**	**$1,827**	**($6,617)**	**$641**	**($25)**	**$50**
Volume variance (assumed to be difference between [D] -[E])							
Monthly Service Charge		$370	$93	$48	$231	$180	$190
Distribution Volumetric Charge		$60	$120	$29	$108	$35	($10)
[F] Volume variance = [D] - [E]		**$430**	**$213**	**$77**	**$339**	**$215**	**$180**
Variance due to rate implementation April / May 1 and other volume effects							
[B] Core revenues billed variance		($547)	$698	($3,174)	($2,042)	$580	($538)
[D] Pro Forma revenue variance		($1,240)	$2,040	($6,540)	$980	$190	$230
[G] Variance due to other		**$693**	**($1,342)**	**$3,366**	**($3,022)**	**$390**	**($768)**

VARIANCE SUMMARY							
[E] Rate variance based on prior year volumes		($1,670)	$1,827	($6,617)	$641	($25)	$50
[F] Volume variance = [D] - [E]		$430	$213	$77	$339	$215	$180
[G] Variance due to other		$693	($1,342)	$3,366	($3,022)	$390	($768)
[B] Core revenues billed variance		**($547)**	**$698**	**($3,174)**	**($2,042)**	**$580**	**($538)**

EXHIBIT 4 - OPERATING COSTS

EXHIBIT 4 - TABLES

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

ORILLIAPOWER

Energizing Our Community

EXHIBIT 4 - TABLES (continued)

EXHIBIT 4 - APPENDICES

MANAGER'S SUMMARY

OM&A 2010 Test Year Expenditures:

Table 4-1 provides a summary of operations, maintenance and administration (OM&A) costs plus amortization expense for 2005 Actual through to 2010 Test. OPDC is proposing recovery of 2010 Test Year OM&A costs totaling $4,346,000. These costs do not include; (1) amortization, (2) PILs and (3) Interest discussed elsewhere in this application. Test year OM&A costs have increased 13.6% from 2005 Actual. On average, this increase is roughly equivalent to an annual increase of 2.7% for five years.

The operating costs presented in this Exhibit represent the annual expenditures required to sustain OPDC's distribution operations. These costs are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place. The 2010 Test Year costs presented were formally approved by OPDC's Board of Directors in July of this year (see Appendix 1-J).

Table 4-1: SUMMARY of Distribution OM&A Costs and Amortization - From 2005 Actual To 2010 Test

Description	(1) 2005 Actual	(2) 2006 Actual	(3) 2007 Actual	(4) 2008 Actual	(5) 2009 Bridge	(6) 2010 Test
SUMMARY OF OPERATIONS, MAINTENANCE, BILLING, ADMINISTRATION AND AMORTIZATION COSTS						
Operations & Maintenance	1,523,300	1,454,900	1,620,400	1,693,000	1,695,000	1,823,000
Billing & Collection	1,245,000	891,900	934,800	916,000	1,086,000	1,041,000
Community Relations	36,000	27,400	37,500	11,400	24,000	21,000
Administration & General	1,021,800	1,233,100	1,282,500	1,268,100	1,400,000	1,461,000
Subtotal before amortization - LDC	**3,826,100**	**3,607,300**	**3,875,200**	**3,888,500**	**4,205,000**	**4,346,000**
Amortization	1,225,100	1,356,200	1,318,100	1,407,200	1,429,000	1,449,000
Total OM&A and Amortization - LDC	**5,051,200**	**4,963,500**	**5,193,300**	**5,295,700**	**5,634,000**	**5,795,000**
% Change Year over Year Before Amortization		**-5.7%**	**7.4%**	**0.3%**	**8.1%**	**3.4%**
% Change Year over Year Including Amortization		**-1.7%**	**4.6%**	**2.0%**	**6.4%**	**2.9%**
% Change - Cumulative From 2005 Before Amortization		**-5.7%**	**1.3%**	**1.6%**	**9.9%**	**13.6%**

Budgeted 2010 OM&A costs will assist OPDC in the achievement of many different objectives. Our mission statement in Exhibit 1, Tab 2 Schedule 1 outlines many of these including the safety of our staff and the public, meeting high standards for reliability and protection of the environment. OPDC strives to provide first class customer service while properly maintaining our system assets and ensuring compliance with all regulatory requirements, codes and statutes.

Income Taxes and Ontario Capital Taxes:

OPDC is subject to payments in lieu of taxes (PILs) under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. While OPDC is exempt from payments under those acts, the calculation of PILs must follow the same rules as in the Income Tax Act (Canada) and must make equivalent payments to the Ontario Minister of Finance.

Table 4-2 below provides a summary of 2005, 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. Further information on the calculation of income taxes (PILs) is contained in Exhibit 4, Tab 8.

Table 4-2: Income Tax Expense per Audited Financial Stmts And Bridge & Test Years

Description	(1) 2005 Actual	(2) 2006 Actual	(3) 2007 Actual	(4) 2008 Actual	(5) 2009 Bridge	(6) 2010 Test
INCOME TAXES (PILS) PER AUDITED FINANCIAL STATEMENTS FROM 2005 TO 2008, 2009 BRIDGE AND 2010 TEST						
Payments in Lieu of Taxes (PILs)	1,198,000	700,000	477,000	473,000	51,200	302,400
Total per Audited FS (to 2008)	**1,198,000**	**700,000**	**477,000**	**473,000**	**51,200**	**302,400**

Materiality Level Selected For Variance Analysis:

The filing requirements for rate applications indicate that the default materiality level for distributors with a revenue requirement of less than $10 million would normally be expected to be $50,000. OPDC has provided explanations for variances greater than $50,000 as required by the filing requirements in this Exhibit.

Business Environment Changes and Associated Cost Drivers:

With respect to the current business environment, Orillia has certainly not been immune to the economic hardship that is impacting both the global and local economy. With several recent business closures and / or reduced production levels, OPDC is feeling the impact of reduced consumption and demand. Unfortunately, when local businesses are negatively impacted by the economic downturn, this translates into reduced employment opportunities and increased collection challenges on residential accounts.

Appendix 4-A provides some news articles and statistics related to both Ontario and specifically Orillia that support our concern about increasing bad debt expenses in spite of OPDC's best efforts and solid collection practices.

A detailed analysis of year over year OM&A variances from 2005 through 2010 is provided in Table 4-6. Included with this table are descriptions of significant cost drivers and an explanation of the impact they had on total OM&A costs in the particular years.

Overall Cost Trends:

OPDC works diligently at managing its costs in all respects. This involves finding the most appropriate utilization of internal staff and contractors that can most cost effectively deliver the required services and utilize purchasing strategies that optimize cost and quantities, as well as seeking out cost saving opportunities where possible by working with other utilities. As a result, OPDC has managed to maintain a five year average annual costs increase of 2.7% for its OM&A costs, despite significant higher cost pressures on many aspects of its overall operations.

Inflation Rates Used for General OM&A:

The inflation rates utilized in Table 4-6 (OM&A Cost Drivers) are based on the Bank of Canada annual inflation rate reported for the years 2006 through 2008. Forecasted inflation rates from the Bank of Canada and economic forecasts from several Canadian chartered banks were utilized to establish conservative inflation estimates of 1% for 2009 and 2% for 2010.

Wages / Benefits / Staffing Levels:

Table 4-10 (Employee Costs) presents a summary of OPDC's staffing complement, compensation and benefits from 2006 Actual through to 2010 Test as required by the filing guidelines.

Drivers of Wage and Related Increases:

OPDC's unionized staff is represented by the International Brotherhood of Electrical Workers (IBEW). The most recent contract negotiations established a three year collective agreement effective September 1, 2007. The settlement called for wage increases of 3.0%, 3.25% and 3.5% over the contract period which expires August 31, 2010. These increases are in line with negotiated contracts of other surrounding LDCs. The prior agreement was also for three years and the average wage increase for that contract was 4%. It has been the practice of OPDC over the years that the Executive /

Management group receive the same annual percentage wage increases as per the union contract.

OPDC must maintain wages that are competitive with surrounding utilities. With an aging workforce, the competition for qualified staff is expected to increase over the next few years and OPDC cannot afford to lose the experienced staff it already has. OPDC must also be able to attract new qualified staff.

Reconciliations to Audited Financial Statements, Driver and Variance Analysis:

Reconciliation between the audited financial statement figures and the “LDC only” costs used as the basis for this application has been provided in Table 4-3. OPDC follows the OEB’s Accounting Procedures Handbook (the “APH”) in distinguishing work performed between operations and maintenance.

The starting point for the driver analysis in Exhibit 4, Tab 2 Table 4-5 is 2005 Actual and thus those figures have been included in Table 4-1 for reference. Detailed information with respect to OM&A costs and variances, arranged by USofA account, is provided in Exhibit 4, Tab 2 Schedule 2.

Table 4-3: Reconciliation of Distribution OM&A Costs and Amortization To Audited Financial Stmts (and Bridge & Test Years)

Description	(1) 2005 Actual	(2) 2006 Actual	(3) 2007 Actual	(4) 2008 Actual	(5) 2009 Bridge	(6) 2010 Test
EXPENSES PER AUDITED FINANCIAL STATEMENTS FROM 2005 TO 2008, 2009 BRIDGE AND 2010 TEST						
Operations, maintenance and administration	3,777,000	3,616,000	3,857,000	3,878,000	4,205,000	4,346,000
Amortization	1,240,000	1,359,000	1,320,000	1,409,000	1,431,000	1,450,000
Total per Audited FS	**5,017,000**	**4,975,000**	**5,177,000**	**5,287,000**	**5,636,000**	**5,796,000**

Description	(1) 2005 Actual	(2) 2006 Actual	(3) 2007 Actual	(4) 2008 Actual	(5) 2009 Bridge	(6) 2010 Test
RECONCILING ITEMS TO ADJUST AUDITED FS TO LDC ONLY PER APPLICATION						
Interest on variances included in administration	69,400	44,600	10,200	11,800	-	-
Less Non-LDC Expenses 5170, 5172, 5186	(28,700)	(69,000)	(9,300)	(9,000)	(8,000)	(8,000)
Amortization of non LDC Plant	(14,900)	(2,900)	(2,100)	(1,800)	(2,000)	(1,000)
Donations not related to customers	(6,600)	(7,000)	(7,800)	(13,500)	(14,000)	(14,000)
Retail services revenues reallocated to other rev	15,000	22,100	25,300	21,700	22,000	22,000
Other including rounding	-	700	-	(500)	-	-
Total OM&A and Amortization - LDC	**5,051,200**	**4,963,500**	**5,193,300**	**5,295,700**	**5,634,000**	**5,795,000**
Unaccounted for differences	**-**	**-**	**-**	**-**	**-**	**-**

SUMMARY OF OM&A AND COST DRIVERS

Overview:

Tab 2 of Exhibit 4 provides information on OPDC's OM&A costs from 2006 Actual through to 2010 Test. Included is a summary of major OM&A categories0, summary of cost drivers, cost per customer and employee ratios, regulatory cost information and other one time and special purpose costs.

Summary of Operations Maintenance and Administration (OM&A) Costs:

Table 4-4 presents a summary of OPDC's total OM&A costs including 2006 EDR (OEB approved), 2006 to 2008 Actual, 2009 Bridge and 2010 Test. Year over year variances are detailed below as well as percentage changes as required by the filing guidelines.

Detailed account by account balances and a description of major accounts are presented in Exhibit 4, Tab 2, Schedule 2.

Summary variances highlighted in Table 4-4 below are explained in Exhibit 4, Tab 3, Schedule 1.

Table 4-4: Summary of OM&A Expenses & Year Over Year Variances

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
SUMMARY OF OPERATIONS, MAINTENANCE, BILLING, ADMINISTRATION AND AMORTIZATION COSTS						
Distribution Operations	542,800	904,500	901,800	1,011,800	1,004,000	1,133,000
Distribution Maintenance	544,300	550,400	718,600	681,200	691,000	690,000
Billing & Collection	932,000	891,900	934,800	916,000	1,086,000	1,041,000
Community Relations	18,100	27,400	37,500	11,400	24,000	21,000
Administration & General	1,167,400	1,233,100	1,282,500	1,268,100	1,400,000	1,461,000
Total Operations Costs - LDC	**3,204,600**	**3,607,300**	**3,875,200**	**3,888,500**	**4,205,000**	**4,346,000**

STATISTICS - PERCENTAGE CHANGES						
Year Over Year		12.6%	7.4%	0.3%	8.1%	3.4%
2010 Test vs 2008 Actual				11.8%		
2010 Test vs 2006 EDR Approved	35.6%					
Average Change From 2006 to 2008				3.9%		
Compound Annual Growth 06 - 08				3.8%		

Description	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
VARIANCES - YEAR OVER YEAR					
Distribution Operations	**361,700**	(2,700)	**110,000**	(7,800)	**129,000**
Distribution Maintenance	6,100	**168,200**	(37,400)	9,800	(1,000)
Billing & Collection	(40,100)	42,900	(18,800)	**170,000**	(45,000)
Community Relations	9,300	10,100	(26,100)	12,600	(3,000)
Administration & General	**65,700**	49,400	(14,400)	**131,900**	**61,000**
Total Variance - Year Over Year	**402,700**	**267,900**	**13,300**	**316,500**	**141,000**

Summary of OM&A Cost Drivers:

Table 4-5 presents OPDC's analysis of significant drivers of cost beginning with total OM&A costs for 2005 Actual and reconciling year by year through to 2010 Test.

The notes following the table provide some additional explanation for the most significant drivers on a year over year basis.

Table 4-5: OM&A Cost Driver Table

COST DRIVER LISTING	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
Actual Expenditures - Previous Year	**3,826,100**	**3,607,300**	**3,875,200**	**3,888,500**	**4,205,000**
# 1 - Labour rate increases	61,000	55,000	64,000	73,000	66,000
# 2 - Inflation	42,000	41,000	60,000	20,000	40,000
# 3 - Regulatory costs	27,000			47,000	
# 4 - Bad debt expense	(375,000)	130,000		150,000	(75,000)
# 5 - Staffing additions / subtractions	45,000	47,000	48,000		83,000
# 6 - Meter exit rebates received	(46,000)				
# 7 - Write off residual value of water heaters	54,000	(54,000)			
# 8 - 3rd party hosting, billing, EBT - transition to contractor	76,000				
# 9 - In 2005 - wrote off 10% of transition costs	(71,000)				
# 10 - Backlot tree trimming - clear backlog (contracted)		59,000	(59,000)		
# 11 - Reduced over-time following implementation of new billing system			(20,000)		
# 12 - Employee performance plan payout			38,000		
# 13 - Reduction in capital taxes and refund for 2007 capital tax			(33,000)		
# 14 - Renegotiated wholesale settlement services contract			(21,000)		
# 15 - Reduction in energy conservation expenditures			(28,000)		
# 16 - Increased preventive air brake maintenance and tree trimming on 44kV				38,000	
# 17 - Eliminate maintenance cost Matthias line				(32,000)	
# 18 - IFRS consulting and support				10,000	20,000
Immaterial unexplained difference	(31,800)	(10,100)	(35,700)	10,500	7,000
Actual Expenditures - Current Year	**3,607,300**	**3,875,200**	**3,888,500**	**4,205,000**	**4,346,000**

Driver Explanations: 2005 Actual to 2006 Actual:

- $61,000 in labour rate increases are based on an average increase rate of 3.5%.

- $42,000 of inflation adjustments are calculated using non-payroll expenditures and applying the Bank of Canada annual inflation rate of 2.33%

- In 2006, there was a year over year decline of $375,000 in bad debts. This variance resulted from recorded bad debts of $315,000 in 2005 and a net recovery of bad debt of $60,000 in 2006. At the 2005 year end, OPDC set up a $174,000 bad debt provision, related to a single commercial customer that was in the process of bankruptcy. Fortunately, the customer's restructuring efforts were successful and OPDC received full recovery of the $174,000 in mid-2006, resulting in the credit in bad debts account for 2006. Factoring out the impact of this single provision and subsequent recovery, OPDC's bad debt expense for 2005 would have been $141,000 and 2006 would have been $114,000.

- In 2006, OPDC completely divested itself from all activities related to water heaters. In that year, the residual value of $54,000 for the remaining water heaters was written off.

- The $76,000 increase in costs for 3rd party hosting, billing and EBT services was driven by an overall long-term goal to streamline the entire billing process. In this process, OPDC switched to a more reasonably priced billing software system and increased the use of a contracted billing service provider where efficiencies and best practices could be drawn upon and produce overall multi-year savings for the company. Although costs temporarily increased in this category, the transition enabled OPDC to reduce internal staff count and reap cost savings in future years.

- In 2005, one-time costs of $71,000 were written off. Transition costs incurred to prepare for market opening were tracked in GL 1570 for future disposition. OPDC opted for a minimum review of the balance in GL 1570 at December 31, 2004 under Phase 2 of the Board's Decision with Reasons dated December 9, 2004. Under this option, a distributor elected to accept 90% of reported transition costs or $60 per customer whichever is less. This $71,000 entry in 2005 had the effect of producing a negative variance in 2006.

Driver Explanations: 2006 Actual to 2007 Actual:

- $55,000 in labour rate increases are based on an average increase rate of 3.0%.
- $41,000 of inflation adjustments are calculated using non-payroll expenditures and applying the Bank of Canada annual inflation rate of 2.19%.
- The $130,000 year over year increase in bad debts is driven by the ($60,000) credit balance at the end of 2006 (see description above) and recorded bad debts of only $70,000 in 2007.
- The $54,000 reduction in water heater expense is simply the reversing effect of the previous year write off – the 2006 expense was a one time event that would not occur in future years, thereby resulting in a year over year decline for 2007.
- There was a $59,000 increase related to backlot tree trimming costs in 2007. This work was undertaken with the use of a subcontractor and is part of OPDC forestry management plan and driven by our goal of minimizing tree-fall / storm related customer outages. This effort was a one-time expense to catch up on a backlog of tree trimming work and to remain on schedule with tree trimming efforts

Driver Explanations: 2007 Actual to 2008 Actual:

- $64,000 in labour rate increases are based on an average increase rate of 3.25%.
- $60,000 of inflation adjustments are calculated using non-payroll expenditures and applying the Bank of Canada annual inflation rate of 3.39%.
- The $59,000 reduction in costs related to tree trimming is simply the reversing effect of costs in 2007, given that the expense was a one time event that would not occur in future years, thereby resulting in a year over year decline for 2008.

Driver Explanations: 2008 Actual to 2009 Bridge:

- $73,000 in labour rate increases are based on an average increase rate of 3.5%.
- $20,000 of inflation adjustments are calculated using non-payroll expenditures and applying an estimated annual inflation rate of 1.0%.
- The $150,000 increase in bad debts expense is driven by a provision that has been recorded for a single large commercial customer that is currently in bankruptcy protection. Given the questionable nature of a recovery on this account, OPDC has set up a $150,000 provision for this potential loss. Unlike almost every other large commercial account in Orillia, OPDC could not obtain credit insurance coverage for this customer and as a result, may be forced to absorb this entire loss, which includes commodity costs and non-competitive charges.

Driver Explanations: 2009 Bridge to 2010 Test:

- $66,000 in labour rate increases are based on an anticipated average increase rate of 3.0%.

- $40,000 of inflation adjustments are calculated using non-payroll expenditures and applying estimated annual inflation rate of 2.0%.

- In 2010, we expect a $75,000 year over year reduction in bad debts expense. This reduction factors in the impact that the major provision incurred in 2009 will not be a repeating event. However, despite improved collection procedures that resulted in reduced bad debts over the past several years, we expect a small increase in uncollectible residential accounts in light of the difficult economic conditions locally.

- The $83,000 increase related to staffing additions is driven by the proposed hiring of a new engineering technician and the associated costs.

Cost Per Customer and Cost Per Employee Ratios:

Table 4-6 below outlines OPDC calculations for OM&A cost per customer and OM&A cost per full time equivalent employee for 2006 Actual through to 2010 Test.

Table 4-6: OM&A Cost per Customer and Full Time Equivalent Employee (FTEE)

Description	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
Number of customers	12,571	12,666	12,815	13,065	13,199
Average of beginning and end of year	12,483	12,619	12,741	12,940	13,132
Total OM&A - LDC	$3,607,300	$3,875,200	$3,888,500	$4,205,000	$4,346,000
OM&A Cost per Customer	**$289**	**$307**	**$305**	**$325**	**$331**
Number of FTEE Employees	27.0	28.3	28.6	28.6	29.6
FTEEs Per Customer	462	446	445	452	444
OM&A Cost per FTEE	**$133,600**	**$136,900**	**$136,000**	**$147,000**	**$146,800**

On an annual basis, OPDC participates in the MEARIE Utility Performance Management Survey. This survey allows OPDC management to benchmark itself against other LDC’s on a variety of statistics and ratios such as those noted above. Through this benchmarking process, management can identify areas for potential improvements and thereby realize future cost reductions.

Regulatory Costs:

Regulatory costs as required by the filing guidelines are presented in Table 4-7. Compliance with Regulation 22/04 has caused a significant increase in documentation and monitoring regarding the distribution system. OPDC will be adding an engineering staff person in 2010 in order to assist with continued compliance in this area.

Table 4-7: Regulatory Costs

Regulatory Cost Category	USoA Account	Ongoing or One-time Cost?	2006 Approved	2008 Actual	2009 Bridge	% Change 2009 Bridge vs 2008	2010 Test	% Change 2010 Test vs 2009 Bridge
1. OEB Annual Assessment	5655	Ongoing	51,698	42,989	45,000	5%	45,000	0%
2. OEB Section 30 Costs (OEB initiated)	5630	Ongoing	0	2,794	13,000	365%	3,000	-77%
3. Consultants costs for regulatory matters	5630	Ongoing	47,208	38,696	55,000	42%	33,000	-40%
4. Operating expenses associated with staff resources allocated to regulatory matters (Regulatory Officer and New Engineering Staff)	5005 / 5610	Ongoing	0	100,299	122,000	22%	198,000	62%
5. Electrical Safety Authority costs for regulatory oversight	5655	Ongoing	6,987	6,734	7,000	4%	7,000	0%
6. 2010 Rate Application Intervener costs - (ONE QUARTER OF TOTAL EXPECTED COST)	5655	One-time	0	0	0	na	25,000	na
7.2010 Rate application consultant costs (ONE QUARTER OF TOTAL EXPECTED COST	5655	One-time	0	0	0	na	10,000	na
8. Letter of Credit - Prudential costs	5665	Ongoing	9,665	9,140	9,000	-2%	9,000	0%
Totals ***			**$115,558**	**$200,652**	**$251,000**	**25.1%**	**$330,000**	**31.5%**

***** Costs are not all inclusive. They do not include all time spent by finance, engineering, accounting, billing staff time involved in regulatory matters. For example none of the Treasurer's or the Controller's time was charged to a regulatory gl in the preparation of this rate application.These costs have been charged to general administration.**

One Time and Special Purpose Costs:

One Time Costs**:** OPDC is projecting to incur some “one-time” costs during 2010 such as consulting and intervener costs for this rate application and consulting for IFRS. For purposes of this application, OPDC has made an assumption that spending on these types of activities will occur over the entire period between rebasing. That is they have been averaged over the four year period of this cost of service rate application. Only one quarter of the expected cost for catagories 6 & 7 in Table 4- 7 have been shown in the table.

Green Energy Act: OPDC has not included expenses that relate to the Green Energy Act. It is our assumption based on communications from the Ontario Energy Board that these costs will be isolated and recovery will be dealt with separately in order to keep OPDC whole for this Provincial Government initiative.

Smart Meter Costs: OPDC is currently installing Sensus smart meters for its residential and small general service community and expects completion late in the fourth quarter of 2009. No operating costs have been included related to smart meters in this application. OPDC intends to bring an application forward to the OEB to recover smart meter capital and operating costs at an appropriate date in the future. OPDC wishes to ensure all capital costs have been accounted for and operating costs are relatively stable before initiating a rate rider application for smart meters.

Charitable Donations: OPDC did not include any charitable donations not related to the welfare of Orillia’s distribution customers in our OM&A expenses. OPDC has typically donated $6,000 to the Salvation Army on an annual basis. This has always been done with the understanding that they would administer it solely for the purpose of assisting OPDC customers experiencing hardship to pay overdue hydro bills.

OPDC intends to honour the obligation on all LDCs participating in the Low Income Assistance Program (LEAP) by making a contribution equal to .12% of the 2010 Test year Revenue Requirement. On a go forward basis, the $6,000 mentioned above would become part of OPDC's LEAP contribution.

Employee Performance Plan: OPDC initiated an Employee Performance Plan in 2008.

The introduction to the plan states that "*Orillia Power's Employee Performance Plan (EPP) is a company-wide, results focused program. It has been designed to encourage employees at all levels to strive for the achievement of specific business results and is closely tied to the Vision and Mission of the organization. The plan will focus on a series of critical business results or measures that encourage dedicated and competent performance, while linking the success of the organization to the success of the employees by providing additional monetary compensation when plan targets are achieved or surpassed."*

This plan is discussed further in Exhibit 4, Tab 4, Schedule 1 and a copy of the plan is attached as Appendix 4-B.

DETAILED ACCOUNT BY ACCOUNT OM&A EXPENSES

Table 4-8 presents a detailed listing, account by account, of OPDC's OM&A costs including 2006 to 2008 Actual, 2009 Bridge and 2010 Test. The notes following the table provide an overview of OPDC accounts.

Table 4-8: Detailed Operations Maintenance & Administration Expenses

Description	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
DISTRIBUTION EXPENSES - OPERATIONS					
5005-Operation Supervision and Engineering	378,500	440,000	500,200	518,000	645,000
5010-Load Dispatching	213,200	232,700	217,200	249,000	261,000
5016-Distribution Station Equipment - Operation Labour	21,400	25,800	21,400	27,000	27,000
5017-Distribution Station Equipment - Operation Supplies and Expenses	167,800	98,600	198,600	160,000	147,000
5020-Overhead Distribution Lines and Feeders - Operation Labour	6,700	10,600	13,100	12,000	13,000
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expen	28,300	30,800	26,500	36,000	38,000
5030-Overhead Subtransmission Feeders - Operation	77,900	57,600	32,100	-	-
5070-Customer Premises - Operation Labour	10,700	5,700	2,700	2,000	2,000
Distribution Expenses - Operation Total	**904,500**	**901,800**	**1,011,800**	**1,004,000**	**1,133,000**
DISTRIBUTION EXPENSES - MAINTENANCE					
5120-Maintenance of Poles, Towers and Fixtures	295,300	501,800	427,400	371,000	396,000
5125-Maintenance of Overhead Conductors and Devices	48,700	49,500	49,200	83,000	102,000
5145-Maintenance of Underground Conduit	112,400	77,100	112,700	109,000	98,000
5160-Maintenance of Line Transformers	44,300	57,100	59,100	70,000	56,000
5170-Sentinel Lights - Labour	5,200	4,800	4,900	4,000	4,000
5172-Sentinel Lights - Materials and Expenses	2,600	4,500	4,100	4,000	4,000
5175-Maintenance of Meters	49,700	33,100	32,800	58,000	38,000
5186-Water heater maintenance	61,200	-	-	-	-
Distribution Exp - Maintenance Total	**619,400**	**727,900**	**690,200**	**699,000**	**698,000**
Less Non-LDC Expenses 5170, 5172, 5186	69,000	9,300	9,000	8,000	8,000
Distribution Exp - Maintenance LDC	**550,400**	**718,600**	**681,200**	**691,000**	**690,000**
BILLING AND COLLECTIONS					
5310-Meter Reading Expense	136,600	123,000	132,400	140,000	145,000
5315-Customer Billing	730,300	662,900	627,800	640,000	664,000
5320-Collecting	73,600	55,000	52,600	50,000	50,000
5330-Collection Charges	11,500	21,200	17,800	21,000	22,000
5335-Bad Debt Expense	(60,100)	72,700	85,400	235,000	160,000
Billing and Collecting Total	**891,900**	**934,800**	**916,000**	**1,086,000**	**1,041,000**
COMMUNITY RELATIONS					
5410-Community Relations - Sundry	7,900	9,200	10,900	24,000	21,000
5415-Energy Conservation	19,500	28,300	500	-	-
Community Relations Total	**27,400**	**37,500**	**11,400**	**24,000**	**21,000**

Table 4-8: Detailed Operations Maintenance & Administration Expenses (Continued)

Description	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
ADMINISTRATION AND GENERAL					
5605-Executive Salaries and Expenses	277,700	291,200	302,500	308,000	319,000
5610-Management Salaries and Expenses	298,000	347,900	372,700	390,000	403,000
5615-General Administrative Salaries and Expenses	172,200	170,000	174,100	178,000	185,000
5620-Office Supplies and Expenses	185,300	172,100	157,200	195,000	210,000
5625-Administrative Expense Transferred-Credit	(331,900)	(318,400)	(325,100)	(316,000)	(330,000)
5630-Outside Services Employed	101,600	93,800	89,300	143,000	125,000
5635-Property Insurance	21,700	20,700	20,900	23,000	24,000
5640-Injuries and Damages	26,400	24,300	25,200	27,000	28,000
5655-Regulatory Expenses	45,300	55,200	48,900	52,000	87,000
5660-General Advertising Expenses	24,700	27,600	27,300	30,000	30,000
5665-Miscellaneous Expenses	27,500	34,500	59,600	70,000	71,000
5675-Maintenance of General Plant	228,200	233,000	235,600	238,000	245,000
Administrative and General Expenses Total	**1,076,700**	**1,151,900**	**1,188,200**	**1,338,000**	**1,397,000**
TAXES OTHER THAN INCOME TAXES					
6105-Taxes Other Than Income Taxes	23,700	24,200	24,900	27,000	27,000
6105-Taxes Other Than Income Taxes - Cap Tax	42,200	43,900	10,600	19,000	6,000
Taxes Other Than Income Taxes Ex CT	**65,900**	**68,100**	**35,500**	**46,000**	**33,000**
OTHER DEDUCTIONS					
6035-Other Interest Expense	84,100	44,700	37,400	10,000	25,000
6205-Donations	13,400	25,600	20,500	20,000	20,000
Other Items Total	**97,500**	**70,300**	**57,900**	**30,000**	**45,000**
Donations not related to customers	7,000	7,800	13,500	14,000	14,000
Other Items Total - LDC	**90,500**	**62,500**	**44,400**	**16,000**	**31,000**
Total OM&A Expenses - LDC	**3,607,300**	**3,875,200**	**3,888,500**	**4,205,000**	**4,346,000**

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of the OPDC electrical system. This includes direct labour and related overhead, non-capital material costs to support both scheduled and reactive maintenance events, vehicle costs based on and charged out at pre-established rates and any contractor costs. OPDC's maintenance strategy is to minimize reactive and emergency-type work through an effective and systematic planned maintenance program.

OPDC's system reliability and responsiveness to customer outage events are monitored closely to ensure that its maintenance strategy is effective. As detailed in OPDC's Asset Management Plan, maintenance efforts, in addition to performing their intended function, also help to identify areas which require more significant improvements and capital investments.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the OPDC distribution system. These activities include pole testing, visual inspections of equipment, transformer oil analysis as well as infrared thermography testing. These different testing methodologies and tools are all utilized with appropriate frequency. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventive Maintenance:

Preventive maintenance activities include inspection, servicing and repair of system components, tree trimming efforts, 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 category is comprised of 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 outage restoration. OPDC constantly evaluates its maintenance data to adjust predictive and preventive actions with the ultimate objective of reducing emergency maintenance. Outside of normal business hours, OPDC has an arrangement with the local fire department, who will contact the “on call” lineperson in the event of service problems.

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 OPDC 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:

OPDC utilizes a Supervisory Control and Data Acquisition (“SCADA”) system to monitor and manage its network. Control centre staff are on site 12 hours a day, seven days a week. In addition to the ‘after hours’ call handling arrangement with the fire department, control centre staff remain on-call via a pager that is linked with the SCADA system and will send a alarm in the event of system problems.

Metering:

OPDC contracts out most of the work related to metering. 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 OPDC's 10 substations. OPDC's substation maintenance strategy is focused on minimizing, to the extent possible, emergency-type work by undertaking proactive and preventive measures for its substations.

ENGINEERING DEPARTMENT

The engineering department is responsible to maintain and update OPDC's system asset data. Engineering is also involved in troubleshooting system problems, delivering underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. Engineering provides drafting services and system mapping for capital projects and distribution system asset management.

STORES/WAREHOUSE

Stores area is responsible for managing the procurement, control, and movement of materials within OPDC'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 operations, maintenance, capital and third party 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 / VEHICLE FLEET

This area assists with the maintenance and control of 13 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 accounts based on number of hours used. A standard hourly cost per hour 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 accounts 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. OPDC is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventive 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. OPDC was recently award the Silver Level for safety by E&USA and has operated for more than six years without a lost time injury.

CUSTOMER SERVICE

The Customer Service group is responsible for the customer care activities for the approximately 12,800 customers in OPDC's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. OPDC strives to consistently deliver first class customer service in an efficient and professional manner. The costs associated with the Customer Service department are collected in accounts 5310 to 5415.

Meter Reading:

Meter reading services are contracted out to a non-affiliated third party under a service contract agreement. Through its contractor, OPDC reads all of its meters each month and bills on actual consumption.

Billing:

OPDC utilizes a third party contractor to assist in the monthly billing and issuance of invoices to customers. 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 account adjustments, processing meter changes and other various account related field service orders and mailing services. OPDC 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. In an effort to minimize credit losses, OPDC enforces a prudent credit policy in accordance with the Distribution System Code. Overdue account collection efforts are handled by OPDC's billing contractor 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 OPDC purchased credit insurance for general service customers to further reduce our risk.

Customer Service & Community Involvement:

OPDC is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. OPDC maintains a presence in the community it serves and has an important role to play in educating the public about electricity safety and energy conservation. OPDC continues to participate with the OPA in administering programs directed at Energy Conservation. OPDC is active in the community promoting conservation initiatives and attending a number of community events each year.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within OPDC, 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 Salaries and Expenses (5605) - Expenses in this category include salaries and all related expenses for the President and Treasurer.
- Management Salaries and Expenses (5610) - Expenses in this category include salaries and all related expenses for the Controller, Regulatory Officer, Human Resources Officer and the Executive Assistant.

- General Administrative Services (5615) - Expenses in this category include salaries and all related expenses for administrative staff including finance, purchasing and payroll.
- Office Supplies and Expenses (5620) – OPDC utilizes this account to track costs that are ultimately shared with an affiliated company, including information technology support.
- Outside Service Employed (5630) - Expenses in this category include consulting and professional fees of accountants and auditors, actuaries, tax consultants, legal and regulatory services.
- Property Insurance & Damages (5635 & 5640) - Expenses in this category include premiums on OPDC's property policy as well as any claim related damage costs.
- Regulatory Expenses (5655) – Regulatory Expenses include the annual cost assessment levied by the OEB and the ESA fees for regulatory oversight. Upon approval or direction by the OEB, regulatory expenses related to rate applications will be charged to this account.
- General Advertising Expenses (5660) - Expenses in this category include OPDC promotion and advertising carried out within the community.
- Miscellaneous General Expense (5665) - Bank Service Charges, memberships and other miscellaneous costs are included in this account.

SUMMARY OF OM&A EXPENSE VARIANCE ANALYSIS

Table 4-4 was presented in Exhibit 4, Tab 2 Schedule 1 and is repeated in this schedule below in order to assist in the summary overview of OPDC major variances. OPDC has prepared a detailed variance analysis on an account by account basis for OM&A costs presented in Exhibit 4 Tab 3 Schedule 2. Amounts highlighted in yellow represent variances identified as material (over $50,000) and are explained in this schedule below the table. Excerpts from the tables are shown before the explanation.

Misclassification Error Identified in OPDC's 2006 EDR Rate Filing:

As part of the submission to the OEB on distribution OM&A expenses, applicants are required to provide a variance analysis between 2006 EDR and the 2006 Actual year. During the preparation of this variance analysis, it became apparent that distribution control centre costs of $258,975 had been included in account 4715 in the 2006 EDR model instead of account 5010. The subsequent oversight by management to notice the misclassification ultimately resulted in OPDC's distribution control centre costs not being recognized as a distribution expense for purposes of calculating revenue requirement in the 2006 EDR model.

Consequently, almost $259,000 was not included in the approved rates for May 1, 2006 and has not been in rates for the 2007, 2008 and 2009 rate year. From 2006 to 2009 OPDC did not collect almost $1,036,000 from its customers which it certainly would have collected had the cost of the control centre been assigned to the proper account number in the first place.

The correction of this omission from the 2006 EDR and the proper inclusion of control centre costs in distribution operations costs accounts for almost 40% of the after tax revenue deficiency outlined in Exhibit 6 of the 2010 rate application.

While OPDC admits that management erred in misclassifying a legitimate distribution cost, the company thoroughly considered its fiduciary obligations in considering seeking retroactive recovery of this significant amount. However, after an assessment of the various implications, including recent OEB decisions in similar situations and customer rate impacts, a decision was made not to seek retroactivity.

While OPDC will not be seeking to recover this amount retroactively, it does want to ensure that it is recoverable on a go forward basis. In the 2010 application, budgeted costs for the control centre of $261,000 have been assigned to account 5010 and have been included in the distribution expenses for the purposes of determining the 2010 revenue requirement and the proposed distribution rates.

Table 4-4: Summary of OM&A Expenses & Year Over Year Variances

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
SUMMARY OF OPERATIONS, MAINTENANCE, BILLING, ADMINISTRATION AND AMORTIZATION COSTS						
Distribution Operations	542,800	904,500	901,800	1,011,800	1,004,000	1,133,000
Distribution Maintenance	544,300	550,400	718,600	681,200	691,000	690,000
Billing & Collection	932,000	891,900	934,800	916,000	1,086,000	1,041,000
Community Relations	18,100	27,400	37,500	11,400	24,000	21,000
Administration & General	1,167,400	1,233,100	1,282,500	1,268,100	1,400,000	1,461,000
Total Operations Costs - LDC	**3,204,600**	**3,607,300**	**3,875,200**	**3,888,500**	**4,205,000**	**4,346,000**

STATISTICS - PERCENTAGE CHANGES						
Year Over Year		12.6%	7.4%	0.3%	8.1%	3.4%
2010 Test vs 2008 Actual				11.8%		
2010 Test vs 2006 EDR Approved	35.6%					
Average Change From 2006 to 2008				3.9%		
Compound Annual Growth 06 - 08				3.8%		

Description	Variance [(2) - (1)]	Variance [(3) - (2)]	Variance [(4) - (3)]	Variance [(5) - (4)]	Variance [(6) - (5)]
VARIANCES - YEAR OVER YEAR					
Distribution Operations	**361,700**	(2,700)	**110,000**	(7,800)	**129,000**
Distribution Maintenance	6,100	**168,200**	(37,400)	9,800	(1,000)
Billing & Collection	(40,100)	42,900	(18,800)	**170,000**	(45,000)
Community Relations	9,300	10,100	(26,100)	12,600	(3,000)
Administration & General	**65,700**	49,400	(14,400)	**131,900**	**61,000**
Total Variance - Year Over Year	**402,700**	**267,900**	**13,300**	**316,500**	**141,000**

Explanation of Variance _ Distribution Operations:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
Distribution Operations	542,800	904,500	901,800	1,011,800	1,004,000	1,133,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
Distribution Operations		**361,700**	(2,700)	**110,000**	(7,800)	**129,000**

Four material factors combined to produce the majority of the $361,700 variance of 2006 EDR to 2006 actual:

- $213,000 is related to the actual cost of running OPDC's control centre in 2006, none of which was included in the 2006 EDR model as previously explained above.

- $52,000 of the variance is due to a staffing increase, with the hiring of an engineering supervisor in late March 2006.

- $50,000 is driven by increased costs in the distribution station maintenance category. In 2006, with the goal of positively influencing reliability and keeping equipment up to date, OPDC undertook additional substation maintenance activities beyond its regularly scheduled maintenance work.

- $51,000 of the variance is the result of additional work carried out on the Matthias subtransmission line. In particular, to enable equipment access for maintenance purposes, a project to clear significant under-growth of brush was required. In addition, replacement of numerous cross arms were required to ensure continued integrity of the line.

The $110,000 variance between 2007 actual to 2008 actual is driven primarily by a $100,000 year over year increase in distribution station maintenance expenditures. The major costs in this category were $47,000 in copper theft and the related repair costs and over $30,000 spent on feeder cable reconfiguration and replacement at the Fittons substation. Also in 2008, there was a $60,000 increase in engineering costs, related primarily to a staffing addition. This increase was virtually offset by reductions in load dispatching costs and maintenance costs on the Matthias subtransmission line.

The $129,000 variance between 2009 (bridge year) to 2010 (test year) is driven by the costs associated with the proposed hire of a new engineering technician as well as reallocation of some existing staff costs that had previously been charged to other GL's but will now be charged to engineering to better reflect the expected use of the employee's time.

Explanation of Variance _ Distribution Maintenance:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
Distribution Maintenance	544,300	550,400	718,600	681,200	691,000	690,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
Distribution Maintenance		6,100	**168,200**	(37,400)	9,800	(1,000)

There are a number of factors that contribute to the $168,200 variance from 2006 to 2007:

- Year over year, an additional $130,000 was spent on tree trimming activities, including $59,000 for contracted tree trimming services. This increase was required to clear up a backlog of forestry work and remain proactive in preventing tree related power disruptions for OPDC's customers.

- The remainder of the variance was related to above average repair work required on distribution lines and customer services as a result of several heavy ice storms that occurred in the winter of 2007.

Explanation of Variance _ Billing & Collection:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
Billing & Collection	932,000	891,900	934,800	916,000	1,086,000	1,041,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
Billing & Collection		(40,100)	42,900	(18,800)	**170,000**	(45,000)

The $170,000 variance from 2008 actual to 2009 (bridge year) is driven almost exclusively by a projected increase in bad debts. Despite improved collection procedures that resulted in reduced bad debts over the past several years, we expect a small increase in uncollectible residential accounts in light of the difficult economic conditions locally. However, the greatest factor impacting the billing and collections category is the current bankruptcy proceeding of a large commercial customer. Given the questionable nature of a recovery on this account, OPDC has set up a $150,000 provision for this potential loss. Unlike almost every other large commercial account in Orillia, OPDC could not obtain credit insurance coverage for this customer and as a result, may be forced to absorb this entire loss, which includes commodity costs and non-competitive charges.

Explanation of Variance _ Administration & General:

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
Administration & General	1,167,400	1,233,100	1,282,500	1,268,100	1,400,000	1,461,000

Variance		[(2) - (1)]	[(3) - (2)]	[(4) - (3)]	[(5) - (4)]	[(6) - (5)]
Administration & General		**65,700**	49,400	(14,400)	**131,900**	**61,000**

The variance of $65,700 between 2006 EDR and 2006 actual is driven almost entirely by interest / carrying charges on regulatory balances that occurred in 2006 and were non-existent in the 2006 EDR.

From 2008 to the 2009 bridge year, there is an increase of $131,900 which is impacted by numerous items:

- $27,000 comes from annual staff salary increases (2009 increases were 3.25%).
- $38,000 of the increase is related to increase in contracted computer support, increase in costs related to accounting software support & external hosting of accounting software and document management system support.
- $54,000 is related to outside services employed, which is primarily driven by regulatory consulting. Increased auditor fees and IFRS consulting round out the balance of the increase in this category.
- The $13,000 remainder of the variance is the result of numerous small items, none of which are individually material.

The variance of $61,000 between 2009 (bridge year) and 2010 (test year) is the result of projected annual salary increases of $30,000 and increased regulatory costs of $35,000. There are several small offsetting items that bring the variance back down to the $61,000 as reported.

DETAILED ACCOUNT BY ACCOUNT OM&A EXPENSE VARIANCE ANALYSIS

OPDC has prepared a detailed variance analysis as required by the filing guidelines on an account by account basis for OM&A costs. The analysis for all material variances (over $50,000) have been highlighted in Table 4-8 of this schedule. Explanations for those variances are provided in this schedule below the table. Excerpts from the tables are shown before the explanation or reconciliation for each general ledger account. Amounts highlighted in yellow are explained.

Table 4-9: Detailed Operations Maintenance & Administration Expenses - VARIANCE ANALYSIS

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
DISTRIBUTION EXPENSES - OPERATIONS							
5005-Operation Supervision and Engineering	378,500	500,200	645,000	**266,500**	70.4%	**144,800**	28.9%
5010-Load Dispatching	213,200	217,200	261,000	47,800	22.4%	43,800	20.2%
5016-Distribution Station Equipment - Operation Labo	21,400	21,400	27,000	5,600	26.2%	5,600	26.2%
5017-Distribution Station Equipment - Operation Sup	167,800	198,600	147,000	(20,800)	-12.4%	**(51,600)**	-26.0%
5020-Overhead Distribution Lines and Feeders - Ope	6,700	13,100	13,000	6,300	94.0%	(100)	-0.8%
5025-Overhead Distribution Lines and Feeders - Ope	28,300	26,500	38,000	9,700	34.3%	11,500	43.4%
5030-Overhead Subtransmission Feeders - Operatio	77,900	32,100	-	**(77,900)**	-100.0%	(32,100)	-100.0%
5070-Customer Premises - Operation Labour	10,700	2,700	2,000	(8,700)	-81.3%	(700)	-25.9%
Distribution Expenses - Operation Total	**904,500**	**1,011,800**	**1,133,000**	**228,500**	**25.3%**	**121,200**	**12.0%**
DISTRIBUTION EXPENSES - MAINTENANCE							
5120-Maintenance of Poles, Towers and Fixtures	295,300	427,400	396,000	**100,700**	34.1%	(31,400)	-7.3%
5125-Maintenance of Overhead Conductors and Dev	48,700	49,200	102,000	**53,300**	109.4%	**52,800**	107.3%
5145-Maintenance of Underground Conduit	112,400	112,700	98,000	(14,400)	-12.8%	(14,700)	-13.0%
5160-Maintenance of Line Transformers	44,300	59,100	56,000	11,700	26.4%	(3,100)	-5.2%
5170-Sentinel Lights - Labour	5,200	4,900	4,000	(1,200)	-23.1%	(900)	-18.4%
5172-Sentinel Lights - Materials and Expenses	2,600	4,100	4,000	1,400	53.8%	(100)	-2.4%
5175-Maintenance of Meters	49,700	32,800	38,000	(11,700)	-23.5%	5,200	15.9%
5186-Water heater maintenance	61,200	-	-	**(61,200)**	-100.0%	-	
Distribution Exp - Maintenance Total	**619,400**	**690,200**	**698,000**	**78,600**	**12.7%**	**7,800**	**1.1%**
Less Non-LDC Expenses 5170, 5172, 5186	69,000	9,000	8,000	**(61,000)**	-88.4%	(1,000)	-11.1%
Distribution Exp - Maintenance LDC	**550,400**	**681,200**	**690,000**	**139,600**	**25.4%**	**8,800**	**1.3%**
BILLING AND COLLECTIONS							
5310-Meter Reading Expense	136,600	132,400	145,000	8,400	6.1%	12,600	9.5%
5315-Customer Billing	730,300	627,800	664,000	**(66,300)**	-9.1%	36,200	5.8%
5320-Collecting	73,600	52,600	50,000	(23,600)	-32.1%	(2,600)	-4.9%
5330-Collection Charges	11,500	17,800	22,000	10,500	91.3%	4,200	23.6%
5335-Bad Debt Expense	(60,100)	85,400	160,000	**220,100**	-366.2%	**74,600**	87.4%
Billing and Collecting Total	**891,900**	**916,000**	**1,041,000**	**149,100**	**16.7%**	**125,000**	**13.6%**
COMMUNITY RELATIONS							
5410-Community Relations - Sundry	7,900	10,900	21,000	13,100	165.8%	10,100	92.7%
5415-Energy Conservation	19,500	500	-	(19,500)	-100.0%	(500)	-100.0%
Community Relations Total	**27,400**	**11,400**	**21,000**	**(6,400)**	**-23.4%**	**9,600**	**84.2%**

Table 4-9: Detailed Operations Maintenance & Administration Expenses - VARIANCE ANALYSIS (Continued)

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
ADMINISTRATION AND GENERAL							
5605-Executive Salaries and Expenses	277,700	302,500	319,000	41,300	14.9%	16,500	5.5%
5610-Management Salaries and Expenses	298,000	372,700	403,000	**105,000**	35.2%	30,300	8.1%
5615-General Administrative Salaries and Expenses	172,200	174,100	185,000	12,800	7.4%	10,900	6.3%
5620-Office Supplies and Expenses	185,300	157,200	210,000	24,700	13.3%	**52,800**	33.6%
5625-Administrative Expense Transferred-Credit	(331,900)	(325,100)	(330,000)	1,900	-0.6%	(4,900)	1.5%
5630-Outside Services Employed	101,600	89,300	125,000	23,400	23.0%	35,700	40.0%
5635-Property Insurance	21,700	20,900	24,000	2,300	10.6%	3,100	14.8%
5640-Injuries and Damages	26,400	25,200	28,000	1,600	6.1%	2,800	11.1%
5655-Regulatory Expenses	45,300	48,900	87,000	41,700	92.1%	38,100	77.9%
5660-General Advertising Expenses	24,700	27,300	30,000	5,300	21.5%	2,700	9.9%
5665-Miscellaneous Expenses	27,500	59,600	71,000	43,500	158.2%	11,400	19.1%
5675-Maintenance of General Plant	228,200	235,600	245,000	16,800	7.4%	9,400	4.0%
Administrative and General Expenses Total	**1,076,700**	**1,188,200**	**1,397,000**	**320,300**	**29.7%**	**208,800**	**17.6%**

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
TAXES OTHER THAN INCOME TAXES							
6105-Taxes Other Than Income Taxes	23,700	24,900	27,000	3,300	13.9%	2,100	8.4%
6105-Taxes Other Than Income Taxes - Cap Tax	42,200	10,600	6,000	(36,200)	-85.8%	(4,600)	-43.4%
Taxes Other Than Income Taxes Ex CT	**65,900**	**35,500**	**33,000**	**(32,900)**	**-49.9%**	**(2,500)**	**-7.0%**

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
OTHER DEDUCTIONS							
6035-Other Interest Expense	84,100	37,400	25,000	**(59,100)**	-70.3%	(12,400)	-33.2%
6205-Donations	13,400	20,500	20,000	6,600	49.3%	(500)	-2.4%
Other Items Total	**97,500**	**57,900**	**45,000**	**(52,500)**	**-53.8%**	**(12,900)**	**-22.3%**
Donations not related to customers	7,000	13,500	14,000	7,000	100.0%	500	3.7%
Other Items Total - LDC	**90,500**	**44,400**	**31,000**	**(59,500)**	**-65.7%**	**(13,400)**	**-30.2%**
Total OM&A Expenses - LDC	**3,607,300**	**3,888,500**	**4,346,000**	**738,700**	**20.5%**	**457,500**	**11.8%**

Explanation of Variance _ Operations Supervision and Engineering:

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5005-Operation Supervision and Engineering	378,500	500,200	645,000	**266,500**	70.4%	**144,800**	28.9%

The $266,500 variance from 2006 actual to the 2010 test year is driven by a number of factors:

- The hiring of a new senior engineering technologist in the third quarter of 2007 and the proposed hire of an additional engineering technician in the first quarter of 2010 account for $175,000 of the variance. The need for these additional staff was driven by significantly increased regulatory compliance and reporting requirements and additional requirements for internal engineering support.

- $18,000 in staff costs that were allocated to maintenance of meters (GL # 5175) in 2006 are now allocated to engineering, to reflect the current utilization patterns of staff time.

- $17,000 in staff costs that were allocated to meter reading expense (GL # 5310) in 2006 are now allocated to engineering, to reflect the current utilization patterns of staff time.

- In 2006, OPDC recovered $11,000 from Hydro One for 5th feeder design work that was performed. This was a one time recovery which essentially reduced the 2006 operating expenses.

- Inflationary pressure, including annual staff increases of 3.0% to 3.5% contributes approximately $45,000 to the variance.

- The $144,800 variance from 2008 actual to the 2010 test year is also driven by a number of factors:

- The proposed hire of an additional engineering technician in the first quarter of 2010 accounts for $83,000 of the variance. The need for this additional staff member was driven by increased regulatory requirements, including regulatory reporting and additional requirements for internal engineering support.

- $18,000 in staff costs that were allocated to maintenance of meters (GL # 5175) in 2006 are now allocated to engineering, to reflect the current utilization patterns of staff time.

- $17,000 in staff costs that were allocated to meter reading expense (GL # 5310) in 2006 are now allocated to engineering, to reflect the current utilization patterns of staff time.

- Inflationary pressure, including annual staff increases of 3.0% to 3.5% contributes approximately $27,000 to the variance.

Explanation of Variance _ Distribution Station Equipment – Operations Supplies

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5017-Distribution Station Equipment - Operation Sup	167,800	198,600	147,000	(20,800)	-12.4%	**(51,600)**	-26.0%

The ($51,600) variance from 2008 actual to the 2010 test year is also driven by two significant items:

- A variance of ($26,500) is related to copper theft. In 2008, with the price of copper at historically high levels, OPDC, like numerous other utilities, experienced increasing issues related to copper theft, particularly at company substations. In 2008, the costs to replace and repair the damage related to copper theft amounted to $47,500. OPDC has taken a number of measures to reduce future losses, however, none of these measures are foolproof and we project costs from copper theft in the amount of $21,000 for 2010.

- The remaining ($25,000) variance is related to reduced costs at OPDC's Fittons substation. In 2008, $30,500 was spent for reconfiguration and replacement of some of the substation feeder cables. In 2010, we have budgeted $5,700 related to the Fittons substation which is more in line with typical annual costs.

Explanation of Variance _ Overhead Subtransmission Feeders - Operations

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5030-Overhead Subtransmission Feeders - Operatio	77,900	32,100	-	**(77,900)**	-100.0%	(32,100)	-100.0%

As a result of the planned system reconfiguration and tie in to the Hydro One grid related to the Matthias sub transmission line, OPDC is planning to sell the remaining segment of this line to Orillia Power Generation Corporation. With that transaction expected to take place at the end of 2009, there are no budgeted maintenance costs in OPDC for 2010, resulting in the above noted variance.

Explanation of Variance _ Maintenance of Poles, Towers and Fixtures

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5120-Maintenance of Poles, Towers and Fixtures	295,300	427,400	396,000	**100,700**	34.1%	(31,400)	-7.3%

The $100,700 variance from 2006 actual to the 2010 test year is driven by a number of factors:

- $34,000 of the increase is due to general repair and maintenance costs. As a subset of this account category, OPDC tracks costs related to general repairs and maintenance. Given that repairs related to storm damage and other unexpected and unplanned repair costs are allocated here, it is difficult to predict the actual costs in any given year. The costs of $79,000 in 2006 are uncharacteristically low for this category. We have utilized a more realistic cost of $113,000 for the 2010 budget, which is more in line with the average costs in this category over the past four years.

- This variance includes a $57,000 increase in tree trimming costs. The variance is driven by costs in this category that were unusually low in 2006. Staff that typically perform the tree trimming work were delayed by work on other projects in 2006, however, the backlog of tree trimming work was cleared with extra attention placed on it in 2007. The costs in this category for 2010 are in-line with the average annual spending on tree trimming activities. The direct customer benefits of OPDC's proactive approach to forestry management and tree trimming were powerfully illustrated when a massive storm hit Southern Ontario on August 20, 2009. Although there was significant tree damage and some local outages, OPDC was able to achieve admirable restoration times and had its customers back on line, long before many other local utilities were able to accomplish full restoration of services.

- $7,000 for OPDC's tree replacement program. As a pillar of OPDC's preventive maintenance program, tree trimming is undertaken with the goal of reducing and preventing outages. Although this often entails removing all or portions of established trees, OPDC is also very cognizant of the environmental impact of removing trees. With this in mind, in 2007, OPDC began a program whereby new trees would be planted in an attempt to 'offset' the removals. There were no costs in this category in 2006 and we have budgeted $7,000 in 2010.

- $4,000 related to load interrupter maintenance. In an effort to improve overall system reliability and thereby reduce outages, OPDC began a more aggressive maintenance program for its load interrupters in 2007. As a result, costs in this category have increased from $3,000 in 2006 to a budgeted level of $7,000 in 2010.

Explanation of Variance _ Maintenance of Overhead Conductors and Devices

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5125-Maintenance of Overhead Conductors and Dev	48,700	49,200	102,000	**53,300**	109.4%	**52,800**	107.3%

The $53,300 variance from 2006 actual to the 2010 test year is driven by a number of factors:

- $21,000 is related to ground rod upgrading that is required to achieve compliance with new / current standards and public safety due diligence.
- $18,000 increase in general maintenance / repair costs. Given that repairs related to storm damage and other unexpected and unplanned repair costs are allocated here, it is difficult to predict the actual costs in any given year. The costs in 2006 are uncharacteristically low for this category. In budgeting this item for 2010, we have utilized a more realistic cost based on a typical year resulting in an $18,000 increase over 2006.
- $15,000 increase in air brake maintenance costs. In an effort improve reliability and system flexibility, in 2009, OPDC began a more aggressive annual air brake maintenance program. These efforts are expected to reduce future outage events and thereby improve reliability.
- $20,000 increase for tree trimming. In a further effort to reduce outages, improved tree trimming was identified as an area where increased proactive actions could be undertaken. Beginning in 2009, additional expenditures were planned in this area with the goal of improving reliability for customers.

- ($21,000) decrease in costs to write off the residual value of a redundant section of line. This was a one time entry related to a section of line that was no longer required within OPDC's system.

The $52,800 variance from 2008 actual to the 2010 test year is driven by a number of factors:

- $18,000 is related to increased efforts for ground rod upgrading that is required to achieve compliance with new / current standards

- $15,000 increase in air brake maintenance costs. In an effort to improve reliability and system flexibility, in 2009, OPDC began a more aggressive annual air brake maintenance program. These efforts are expected to reduce future outage events and thereby improve reliability.

- $20,000 increase for tree trimming. In a further effort to reduce outages, improved tree trimming was identified as an area where increased proactive actions could be undertaken. Beginning in 2009, additional expenditures were planned in this area with the goal of improving reliability for customers.

Explanation of Variance _ Water Heater Maintenance

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5186-Water heater maintenance	61,200	-	-	**(61,200)**	-100.0%	-	

In 2006, OPDC completely divested itself from all activities related to water heaters. In that year, final maintenance requirements were carried out and the residual value of the remaining water heaters was written off. With no further costs recorded in this category after 2006, the result is the negative variance to 2010.

Explanation of Variance _ Customer Billing

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5315-Customer Billing	730,300	627,800	664,000	**(66,300)**	-9.1%	36,200	5.8%

Through effective use of both internal staff and contract billing service providers, OPDC has managed to reduce its overall costs in this account by $66,300 between 2006 and 2010. The factors that impact this reduction are as follows:

- $27,000 increase in third party hosting billing and EBT. In an effort to streamline the entire billing process, OPDC has increased the use of a contracted billing service provider where efficiencies and best practices could be drawn upon and produce overall savings for the company. The cost increase in this category is driven by annual cost increases under the contract and costs for additional services provided by the contractor when OPDC reduced internal staff count.

- $12,000 increase in third party bill printing services. The cost increase in this category is driven by annual cost increases under the contract.

- $5,000 increase in billing supplies & courier costs. The cost increase in this category represents increased costs for items such as invoice stock as well as courier related costs.

- $95,000 reduction in labour costs. As noted above, OPDC has been able to realize efficiencies through its billing model and as a result, direct labour costs within the department have fallen significantly.

- $15,000 reduction in wholesale settlement services costs. In 2008, OPDC identified an opportunity to switch service providers for wholesale settlement services. The contract with the new provider resulted in annual savings of $15,000.

Explanation of Variance _ Bad Debt Expense

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5335-Bad Debt Expense	(60,100)	85,400	160,000	**220,100**	-366.2%	**74,600**	87.4%

The $220,100 variance from 2006 actual to the 2010 test year is driven by a number of factors:

In 2006, OPDC recovered $174,000 in bad debts that had been provisioned in December 2005. This recovery was related to a single commercial customer that was in the process of bankruptcy restructuring. At the 2005 year end, OPDC set up the bad debt provision as a conservative approach, given the risk of loss was high. Fortunately, the customer's restructuring efforts were successful and OPDC received full recovery of the $174,000 in mid-2006, resulting is the credit in bad debts account for 2006. Factoring out this recovery, OPDC's bad debt expense for 2006 would have been $114,000.

In 2010, OPDC has budgeted for $160,000 in bad debt expense which includes $40,000 in expected premiums for a credit insurance policy. In light of the difficult economy both locally (with several business closures) and on a broader scale, it is anticipated that there will be increased collection issues and upward pressure on bad debts. This upward pressure is **expected to continue over the next few years** until the US economy starts moving in a positive direction and those effects are felt in Ontario.

To mitigate the downside risk of non-payment from larger commercial accounts, OPDC made the decision in 2007 to put in place a credit insurance policy. This insurance has already benefited OPDC during the bankruptcy proceedings of a major commercial customer in 2008. Furthermore, given that OPDC's exposure is multiplied by having to absorb 'flow through costs' such as electricity commodity costs when a customer fails to pay, this insurance is a prudent financial tool to manage risk.

The $74,600 variance from 2008 actual to the 2010 test year is driven by a number of factors:

As noted above, the difficult economic conditions have led OPDC to increase its expected bad debt expense by $49,000. In addition, credit insurance premiums are expected to increase by $25,000 from 2008 to 2010, but given the significant potential exposure, it still represents an excellent risk mitigation tool.

Explanation of Variance _ Management Salaries and Expenses

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5610-Management Salaries and Expenses	298,000	372,700	403,000	**105,000**	35.2%	30,300	8.1%

The $105,000 variance from 2006 actual to the 2010 test year is driven by a number of factors:

- $79,000 for the hiring of a regulatory officer. In late 2006, OPDC created a position for a regulatory officer to adequately address the increased requirements for regulatory reporting and other regulatory functions. $79,000 is the incremental cost between the full year of costs for 2010 versus the partial year costs for 2006.

- Annual salary increases for management staff represent the balance of this variance.

Explanation of Variance _ Office Supplies and Expenses

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
5620-Office Supplies and Expenses	185,300	157,200	210,000	24,700	13.3%	**52,800**	33.6%

The $52,800 variance from 2008 actual to the 2010 test year is driven by a number of factors:

- *NOTE: In order to ensure an accurate allocation of shared costs across affiliates, OPDC records shared IT and other similar costs in GL 5620. We recognize that these costs would not typically be recorded in office supplies. However, this has been done to accommodate our accounting system requirements for shared service allocations. Much of the increase in this account relates to planned computer information system development and training to improve productivity and efficiency.*

- $7,000 increase in contracted computer support. Along with accounting software support noted below, these costs are rising marginally as OPDC focuses on utilizing contracted subject matter experts to efficiently support our IT requirements and to ensure integrity of all our systems and data security.

- $6,000 increase in costs related to accounting software support & external hosting of accounting software.

- $10,000 for Great Plains (financial software package) report development & customization. To further leverage OPDC's investment in its financial software package, we have budgeted for consulting assistance to develop financial reporting tools that will result in increased operating efficiencies in day to day operations and monthly reporting and financial statement generation.

- $15,000 for document management system support. In 2009, OPDC planned to implement a document management system in order to recognize incremental efficiency gains within the office. The system will be utilized to provide an organized methodology for digital storage and retrieval of documents that are utilized by staff in engineering, finance, billing, regulatory and administration functions. In addition to providing ready access to documents that are currently stored in hard copy format in various secured locations, the document management system will be integrated with

OPDC's existing billing system to improve customer service through improved access to customer information and account history.

- $16,000 increase in general supplies and services. Charges to this category are varied and include: subscriptions, professional fees and dues, printing of customer newsletters, photocopier maintenance and document shredding.

Explanation of Variance _ Other Interest Expense

Description	2006 Actual (1)	2008 Actual (2)	2010 Test (3)	Variance [(3) - (1)]	% Change [(3) - (1)]	Variance [(3) - (2)]	% Change [(3) - (2)]
6035-Other Interest Expense	84,100	37,400	25,000	**(59,100)**	-70.3%	(12,400)	-33.2%

The entire variance is driven by interest / carrying charges on regulatory balances that occurred in 2006 and are expected to be immaterial in the 2010 test year. In 2006, interest / carrying charges of $44,600 on regulatory balances were also charged to GL 4405 (other interest income).

EMPLOYEE COMPENSATION

The purpose of Exhibit 4, Tab 4, Schedule 1 is to summarize OPDC's staff count, employee compensation, benefits, collective agreement implications and staff incentives. In 2008, OPDC implemented an Employee Performance Plan, which is described below.

Table 4-10 below presents a summary of OPDC's staffing complement, compensation and benefits from 2006 Actual through to 2010 Test as required by the filing guidelines. The guidelines allow that reporting under sections where there are three or fewer employees is not required and that the applicant may aggregate this category with the category to which it is most closely related. OPDC has aggregated the executive and management staff together in the management category.

Union Contracts:

OPDC's unionized staff are represented by the International Brotherhood of Electrical Workers (IBEW). The most recent contract negotiations established a three year collective agreement effective September 1, 2007. The settlement called for annual wage increases of 3.0%, 3.25% and 3.5% over the contract period which expires August 31, 2010. The prior agreement was also for three years and the average wage increase for that contract was 4%. OPDC participates in the MEARIE salary survey on an annual basis and feels that our pay rates are competitive with other similar LDCs.

Executive / Management:

It has been the practice of OPDC over the years that the Executive / Management group receive the same annual percentage wage increases as per the union contract.

Employee Performance Plan:

In 2008, Orillia Power Corporation launched the Employee Performance Plan (EPP), with the primary goal of encouraging employees at all levels to strive for the achievement of specific business results and to further support the Vision and Mission of the organization. The plan focuses on a series of critical business results or targets that encourage dedicated and competent performance, while linking the success of the organization to the success of the employees. On an annual basis, the Board of Directors develops and approves annual performance targets and the potential EPP payout. The performance targets focus on three key areas of our business: (1) Health, Safety & Environment, (2) Service Quality and (3) System Reliability and Efficiency.

The plan targets have been designed to provide both immediate and long-term benefits to the customers of OPDC.

- By reinforcing the importance of Health, Safety & Environment through specific plan targets, employees are further encouraged to keep these matters front of mind, in everything they do. OPDC believes strongly in nurturing a culture of safety, and by including it as an integral component of the EPP, we hope to further reduce the possibility of incurring the human and financial costs associated with a Health & Safety incident.

- The Service Quality measures within the plan act to consistently emphasize the focus and importance that OPDC places on satisfying customer needs and expectations. EPP targets in this category are set at levels substantially above the OEB targets to further drive our performance and achieve best in class results.

- In the eyes of the customers, System Reliability is clearly one of the most important measures of their local utility. In the past, OPDC has achieved admirable results with respect to Reliability and Efficiency measures. By setting EPP targets that exceed industry averages, OPDC is further reinforcing the long-term goal of achieving excellent Reliability and Efficiency results and guiding employee efforts to achieve that end. OPDC believes strongly that the proactive measures taken to ensure reliability and efficiency are an investment that saves customers money and inconvenience.

At the end of each year, the total available EPP payout is calculated based on staff's ability to achieve or surpass the pre-established plan targets. To encourage a team oriented approach to organizational success, all OPDC employees share in earned payout on a pro-rata basis. A copy of OPDC's Employee Performance Plan is attached as Appendix 4-B.

Head Count and Employee Compensation:

Table 4-10 shows OPDC's FTEE headcount and compensation for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and 2010 Test Year.

Table 4-10: Employee Costs

Description	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
Number of Employees (FTE's)					
Management	6.1	7.2	7.3	7.3	7.3
Union	20.9	21.1	21.3	21.3	22.3
Total	27.0	28.3	28.6	28.6	29.6
Number of Part Time Employees					
Management					
Union	3.0	3.0	5.0	4.0	4.0
Total	3.0	3.0	5.0	4.0	4.0
TOTAL SALARIES AND WAGES					
Management	484,124	613,816	656,887	679,141	702,025
Union (includes part time employees)	1,355,124	1,362,960	1,462,913	1,525,926	1,637,731
Total Salaries and Wages	1,839,248	1,976,776	2,119,800	2,205,067	2,339,756
TOTAL BENEFITS					
Management	87,729	112,137	120,762	126,129	133,988
Union (includes part time employees)	241,691	243,660	262,021	279,214	309,472
Total Benefits	329,420	355,797	382,783	405,343	443,460
TOTAL COMPENSATION (SALARY, WAGES AND BENEFITS)					
Management	571,852	725,953	777,649	805,270	836,013
Union (includes part time employees)	1,596,815	1,606,621	1,724,933	1,805,140	1,947,203
Total Compensation	2,168,667	2,332,574	2,502,582	2,610,410	2,783,216

Table 4-10: Employee Costs (Continued)

Description	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
COMPENSATION - AVERAGE PER EMPLOYEE					
Yearly Base Wages - Average per Employee					
Management	80,930	83,420	86,490	89,520	92,650
Union (includes part time employees)	54,900	57,440	59,220	61,290	63,530
Total	59,980	64,050	66,180	68,490	70,710
Yearly Overtime - Average per Employee					
Management	1,000	1,130	790	790	790
Union (includes part time employees)	7,410	6,150	6,080	6,080	5,810
Total	5,960	4,870	4,730	4,730	4,570
Yearly Incentive Pay - Average per Employee					
Management	990	700	2,700	2,720	2,720
Union	180	200	1,120	1,130	1,080
Total	360	330	1,520	1,540	1,490
Yearly Benefits - Average per Employee					
Management	15,080	15,570	16,540	17,280	18,350
Union	11,410	11,840	12,320	13,050	13,880
Total	12,080	12,790	13,390	14,130	14,980
TOTAL COMPENSATION CHARGED TO OM&A					
Total Compensation	2,168,667	2,332,574	2,502,582	2,610,410	2,783,216
Total Compensation Charged to OM&A	1,826,095	2,070,917	2,102,200	2,220,410	2,383,216
Total Compensation Capitalized	165,303	187,216	172,482	180,000	190,000

Total compensation does not include OPDC compensation costs charged for work performed for affiliates and subsequently recovered through fully allocated cost pricing.

Staffing Changes:

The following summarizes OPDC staffing changes during the period from 2006 EDR through to 2010 Test. Table 4-11 summarizes staff count position by position from 2004 to 2010. For completeness, Table 4-12 illustrates OPDC's staff count AFTER allocation of staff to our affiliate OPGC. This table and the allocation is discussed in detail in Exhibit 4 Tab 5 Schedule 1 on shared services.

2006 Board Approved to 2006 Actual

There was an increase of two management staff subsequent to the 2006 EDR filing. An Engineering Supervisor was hired March 2005 and a Regulatory Officer was hired August 2006. There were also changes in union staff with a net decline of one staff. Two retirements in this period included a control room operator July 2005 and one of our billing staff July 2006. An apprentice lineman was hired May 2006 in anticipation of the retirement of one of our experienced line staff. OPDC expects to lose more experienced workers through retirement in the next 10 years and will need to have trained staff to replace them.

2006 Actual to 2007 Actual

Although there were no additions to management staff in 2007, a review of FTEE positions resulted in the equivalent of an increase of one management staff. Increasing regulatory compliance and reporting requirements in finance, distribution and engineering departments found both management and union staff devoting more time to OPDC. This review is performed annually. There were changes in union staff but only a minor change in total FTEE union staff count due to the FTEE review. One of our customer service staff retired January 2007 and a Senior Engineering Technician was hired September 2007.

2007 Actual to 2008 Actual

The annual review of FTEE positions resulted in minor changes with no material impact on management or union staff FTEE counts. There were no changes in management or union staff in this period.

2008 Actual to 2009 Bridge Year

No changes in management and union staff are expected in this period. As well, the annual review of FTEE positions performed this period does not anticipate any changes.

2009 Bridge Year to 2010 Test Year

OPDC has budgeted to hire an Engineering Technician in early 2010. This staff position will be predominantly involved in ensuring compliance with ESA Regulation 22/04. Regulation 22/04 requires significantly more engineering resources than in the past. The engineering deficiency in this area has required the involvement of other non-engineering management staff compromising their ability to perform their normal duties.

Table 4-11: Employee Count BEFORE Allocation

Description	2004 Actual (1)	2005 Actual (2)	2006 Actual (3)	2007 Actual (4)	2008 Actual (5)	2009 Bridge (6)	2010 Test (7)
EMPLOYEE COUNT BEFORE ALLOCATION							
LOCAL DISTRIBUTION COMPANY							
Lines	10.0	10.0	11.0	11.0	11.0	11.0	11.0
Engineering	1.0	2.0	2.0	3.0	3.0	3.0	4.0
Operations Control Room	4.0	3.0	3.0	3.0	3.0	3.0	3.0
Billing / Cash / Collections / Reception	6.0	6.0	5.0	4.0	4.0	4.0	4.0
Regulatory Officer			1.0	1.0	1.0	1.0	1.0
Customer service rep	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mechanic	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Janitorial	1.0	1.0	1.0	1.0	1.0	1.0	1.0
OPDC Employees	**24.0**	**24.0**	**25.0**	**25.0**	**25.0**	**25.0**	**26.0**
SHARED SERVICES _ FINANCE & ADMINISTRATION							
General Administration	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Finance / Accounting	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Purchasing / Stores	1.0	1.0	1.0	1.0	1.0	1.0	1.0
OPDC Employees - Shared Admin	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**
OPDC Employees - Total Before Allocation	**32.0**	**32.0**	**33.0**	**33.0**	**33.0**	**33.0**	**34.0**
GENERATION COMPANY							
OPGC Employees	**10.0**	**10.0**	**10.0**	**9.0**	**10.0**	**10.0**	**10.0**
CONSOLIDATED OPC PERMANENT FTEE	**42.0**	**42.0**	**43.0**	**42.0**	**43.0**	**43.0**	**44.0**

Table 4-12: Employee Count AFTER Allocation

Description	2004 Actual (1)	2005 Actual (2)	2006 Actual (3)	2007 Actual (4)	2008 Actual (5)	2009 (6)	2010 Test (7)
EMPLOYEE COUNT AFTER ALLOCATION							
ALLOCATION OF STAFF FTEE TO OPDC & OPGC							
DISTRIBUTION							
OPDC Employees Before Allocations	32.0	32.0	33.0	33.0	33.0	33.0	34.0
Allocation of shared employees to OPGC							
Shared Administration employees	(3.0)	(3.1)	(3.5)	(2.6)	(2.3)	(2.3)	(2.3)
Shared Engineering and Operations employees	(2.5)	(2.5)	(2.5)	(2.1)	(2.1)	(2.1)	(2.1)
Total DISTRIBUTION FTEE after Allocations	**26.5**	**26.4**	**27.0**	**28.3**	**28.6**	**28.6**	**29.6**
GENERATION							
OPGC Employees Before Allocations	10.0	10.0	10.0	9.0	10.0	10.0	10.0
Allocation of Shared Administration employees to O	3.0	3.1	3.5	2.6	2.3	2.3	2.3
Allocation of Engineering and Operations employee	2.5	2.5	2.5	2.1	2.1	2.1	2.1
Total GENERATION FTEE after allocations	**15.5**	**15.6**	**16.0**	**13.7**	**14.4**	**14.4**	**14.4**
CONSOLIDATED OPC PERMANENT FTEE	**42.0**	**42.0**	**43.0**	**42.0**	**43.0**	**43.0**	**44.0**
TOTAL STAFF COUNT WITH SHARED ALLOCATION INCLUDED							
Orillia Power Distribution	26.5	26.4	27.0	28.3	28.6	28.6	29.6
Orillia Power Generation	15.5	15.6	16.0	13.7	14.4	14.4	14.4
CONSOLIDATED OPC PERMANENT FTEE	**42.0**	**42.0**	**43.0**	**42.0**	**43.0**	**43.0**	**44.0**
% OF STAFF WORKING DIRECTLY FOR SUBSIDIAIRIES (USED FOR ALLOCATION OF SHARED ADMINISTRATION COSTS)							
Local Distribution Corporation	63.0%	63.0%	63.0%	67.0%	67.0%	67.0%	67.0%
Generation Corporation	37.0%	37.0%	37.0%	33.0%	33.0%	33.0%	33.0%
Consolidated	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Benefits:

A comprehensive and competitive benefits package exists which includes health and dental insurance and vacation. OPDC pays certain health, dental, and life insurance benefits on behalf of its retired employees. The benefits package is designed to address the health and welfare needs of the employee population with similar plans for both union and management employees.

OPDC's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Table 4-13 summarizes employee pension and other benefit costs for 2006 Actual through to 2010 Test.

Table 4-13: Employee Pension and Other Benefits

Description	2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
PENSION AND BENEFITS SUMMARY					
LOCAL DISTRIBUTION COMPANY					
OMERS Contributions	118,000	131,000	141,000	143,000	151,000
Benefit Premiums - Active Employees	180,000	186,000	203,000	224,000	248,000
Post Retirement Benefit Costs	68,000	62,000	54,000	48,000	41,000
Total	**366,000**	**379,000**	**398,000**	**415,000**	**440,000**

SHARED SERVICES / CORPORATE COST ALLOCATION

Appendix 4-C provides a complete summary of all services between affiliates, OPDC's shared services methodology and prices paid to or charged for services provided to and from affiliates in 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge and 2010 Test.

The activities of OPDC and OPGC are bound by a Services Agreement attached as Exhibit 1 Appendix 1-E. The activities detailed under Article 1 include shared administration, office rent and maintenance of the service centre, monitoring of OPGC generation facilities, maintenance of substations and the purchase of energy produced by OPGC's Matthias Generating Station. Cost allocation methodology applied to these services is cost plus a reasonable rate of return on invested capital as described in Article 2. With amendments to the Affiliate Relationships Code (ARC) May 16, 2008, cost-based pricing will be applied for shared corporate services as defined under ARC.

OPDC has previously received certain exemptions from ARC granted by the Ontario Energy Board. OPDC exemptions to ARC are attached as Exhibit 1 Appendix 1-F. Exemptions granted were felt to be in the public's best interest. These exemptions allow the achievement of economic efficiencies and savings to be passed on to OPDC customers and no party is in any way harmed by the exemptions.

An exemption from ARC allows OPDC to share confidential information and employees that are involved in the operation of OPDC's distribution business for purposes of providing services to each other in accordance with the Services Agreement. Had it not received the exemptions, OPDC would have incurred many new costs including the hiring of separate senior management staff for each of its subsidiaries. The additional costs incurred in the distribution business would then in turn have been passed on to OPDC customers with no increased level of service being provided.

An exemption from ARC allows OPDC to purchase electricity from OPGC to fulfill its obligation to sell electricity to consumers under standard supply service. OPGC is relatively small and sells electricity at a price established by the Province. OPGC in no way influences the price that OPDC customers pay for electricity nor does it rely on OPDC customer information in any decisions that it makes.

Shared administration costs are allocated based on the OPDC FTEE as a percentage of the consolidated OPC permanent FTEE as shown in Table 4-11 and Table 4-12. A review of percentage time spent by each staff member on administrative duties for each affiliate is performed by management during the annual budget process and other times as necessary. This involves, among other things, a review of job descriptions and discussions with staff and management. Specific duties change and evolve over time, as do the procedures and processes developed to meet company reporting requirements.

Rent for the Service Centre is calculated based on the square footage of office space used by OPGC within the service building. Our Control Centre provides SCADA monitoring services for OPDC infrastructure and OPGC generating stations. OPDC staff in the Control Centre primarily provides monitoring but also support engineering administrative functions. The Control Centre operates 24 – 7 and is manned 12 hours per day. After hours, overtime is charged directly to the affiliate for whom the call was initiated. Allocation of costs for the Service Centre and the Control Center are reviewed annually by management.

Services other than shared services provided by OPDC to OPGC are documented in detail in Article 1.01 of the Services Agreement and services other than shared services provided by OPGC to OPDC are documented in detail in Article 1.02 of the Services Agreement. Services provided to or by our affiliates, the City of Orillia and formerly to SCBN Telecommunications Inc, are related mainly to distribution operations. Streetlight maintenance and capital projects initiated by the City create a need for services that are incidental to OPDC operations.

Pricing methodology for services between affiliates other than shared services between OPDC and OPGC are market-based. For example, contract work performed for OPGC and the City of Orillia is charged using fully allocated cost plus a rate of return. Fully allocated cost includes labour plus payroll burden, materials plus stores burden and vehicle overhead costs.

Orillia Power Corporation pays all OPDC Board costs.

Table 4-11: Employee Count BEFORE Allocation

Description	2004 Actual (1)	2005 Actual (2)	2006 Actual (3)	2007 Actual (4)	2008 Actual (5)	2009 Bridge (6)	2010 Test (7)
EMPLOYEE COUNT BEFORE ALLOCATION							
LOCAL DISTRIBUTION COMPANY							
Lines	10.0	10.0	11.0	11.0	11.0	11.0	11.0
Engineering	1.0	2.0	2.0	3.0	3.0	3.0	4.0
Operations Control Room	4.0	3.0	3.0	3.0	3.0	3.0	3.0
Billing / Cash / Collections / Reception	6.0	6.0	5.0	4.0	4.0	4.0	4.0
Regulatory Officer			1.0	1.0	1.0	1.0	1.0
Customer service rep	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mechanic	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Janitorial	1.0	1.0	1.0	1.0	1.0	1.0	1.0
OPDC Employees	**24.0**	**24.0**	**25.0**	**25.0**	**25.0**	**25.0**	**26.0**
SHARED SERVICES _ FINANCE & ADMINISTRATION							
General Administration	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Finance / Accounting	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Purchasing / Stores	1.0	1.0	1.0	1.0	1.0	1.0	1.0
OPDC Employees - Shared Admin	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**
OPDC Employees - Total Before Allocation	**32.0**	**32.0**	**33.0**	**33.0**	**33.0**	**33.0**	**34.0**
GENERATION COMPANY							
OPGC Employees	**10.0**	**10.0**	**10.0**	**9.0**	**10.0**	**10.0**	**10.0**
CONSOLIDATED OPC PERMANENT FTEE	**42.0**	**42.0**	**43.0**	**42.0**	**43.0**	**43.0**	**44.0**

Table 4-12: Employee Count AFTER Allocation

Description	2004 Actual (1)	2005 Actual (2)	2006 Actual (3)	2007 Actual (4)	2008 Actual (5)	2009 (6)	2010 Test (7)
EMPLOYEE COUNT AFTER ALLOCATION							
ALLOCATION OF STAFF FTEE TO OPDC & OPGC							
DISTRIBUTION							
OPDC Employees Before Allocations	32.0	32.0	33.0	33.0	33.0	33.0	34.0
Allocation of shared employees to OPGC							
Shared Administration employees	(3.0)	(3.1)	(3.5)	(2.6)	(2.3)	(2.3)	(2.3)
Shared Engineering and Operations employees	(2.5)	(2.5)	(2.5)	(2.1)	(2.1)	(2.1)	(2.1)
Total DISTRIBUTION FTEE after Allocations	**26.5**	**26.4**	**27.0**	**28.3**	**28.6**	**28.6**	**29.6**
GENERATION							
OPGC Employees Before Allocations	10.0	10.0	10.0	9.0	10.0	10.0	10.0
Allocation of Shared Administration employees to O	3.0	3.1	3.5	2.6	2.3	2.3	2.3
Allocation of Engineering and Operations employee	2.5	2.5	2.5	2.1	2.1	2.1	2.1
Total GENERATION FTEE after allocations	**15.5**	**15.6**	**16.0**	**13.7**	**14.4**	**14.4**	**14.4**
CONSOLIDATED OPC PERMANENT FTEE	**42.0**	**42.0**	**43.0**	**42.0**	**43.0**	**43.0**	**44.0**
TOTAL STAFF COUNT WITH SHARED ALLOCATION INCLUDED							
Orillia Power Distribution	26.5	26.4	27.0	28.3	28.6	28.6	29.6
Orillia Power Generation	15.5	15.6	16.0	13.7	14.4	14.4	14.4
CONSOLIDATED OPC PERMANENT FTEE	**42.0**	**42.0**	**43.0**	**42.0**	**43.0**	**43.0**	**44.0**
% OF STAFF WORKING DIRECTLY FOR SUBSIDIAIRIES (USED FOR ALLOCATION OF SHARED ADMINISTRATION COSTS)							
Local Distribution Corporation	63.0%	63.0%	63.0%	67.0%	67.0%	67.0%	67.0%
Generation Corporation	37.0%	37.0%	37.0%	33.0%	33.0%	33.0%	33.0%
Consolidated	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Shared Service Variance Analysis:

Variances in shared services between 2010 Test Year and 2006 Board Approved and 2010 Test Year and 2008 Actual are shown in Table 4-14. Commentary on significant variances (over $50,000) follows the table.

Table 4-14: Shared Services Variance Analysis

Description	2006 EDR (1)	2006 Actual (2)	2007 Actual (3)	2008 Actual (4)	2009 Bridge (5)	2010 Test (6)
DISTRIBUTION EXPENSE INCURRED THROUGH SERVICES SHARED WITH AFFILIATES:						
Administration services	516,000	565,000	586,000	607,000	643,000	671,000
SCADA monitoring services	259,000	213,000	234,000	223,000	249,000	261,000
Service Centre rent	163,000	194,000	199,000	200,000	202,000	208,000
DISTRIBUTION EXPENSE PAID TO AFFILIATES:						
OPGC - contract services	247,000	325,000	248,000	308,000	325,000	328,000
OPGC - power purchased	834,000	921,000	758,000	1,052,000	600,000	-
City of Orillia	123,000	139,000	161,000	195,000	188,000	190,000
SCBN Telecommunications	28,000	32,000	8,000	-	-	-

VARIANCE ANALYSIS	Variance [(6) - (1)]	% Change [(6) - (1)]	Variance [(6) - (4)]	% Change [(6) - (4)]
DISTRIBUTION EXPENSE INCURRED THROUGH SERVICES SHARED WITH AFFILIATES:				
Administration services	**155,000**	30.0%	**64,000**	10.5%
SCADA monitoring services	2,000	0.8%	38,000	17.0%
Service Centre rent	45,000	27.6%	8,000	4.0%
DISTRIBUTION EXPENSE PAID TO AFFILIATES:				
OPGC - contract services	**81,000**	32.8%	20,000	6.5%
OPGC - power purchased	**(834,000)**	-100.0%	**(1,052,000)**	-100.0%
City of Orillia	**67,000**	54.5%	(5,000)	-2.6%
SCBN Telecommunications	(28,000)	-100.0%	-	na

Explanation of Variance _ Administrative Services:

VARIANCE ANALYSIS		Variance [(6) - (1)]	% Change [(6) - (1)]	Variance [(6) - (4)]	% Change [(6) - (4)]
DISTRIBUTION EXPENSE INCURRED THROUGH SERVICES SHARED WITH AFFILIATES:					
Administration services		**155,000**	30.0%	**64,000**	10.5%

From 2006 Board Approved to the 2010 test year, there is an increase of $155,000 in administration services due to the following:

- $28,000 of the increase is related to contracted computer support, accounting software support & external hosting of accounting software and document management system support.
- $80,000 of the increase is related to increases in management and administrative salaries averaging 3% per year.
- $40,000 of the increase is related to the change in the percentage of shared services allocated to OPDC from 63% in 2006 Board Approved to 67% in the 2010 test year as documented in Exhibit 4, Tab 4 Schedule 1.
- $7,000 remainder of the variance is related to an increase in cost of supplies and expenses, none of which are material.

From 2008 Actual to the 2010 test year, there is an increase of $64,000 in administration services due to the following:

- $25,000 of the increase is related to contracted computer support, accounting software support and document management system support.
- $29,000 of the increase is related to an increase in management and administrative salaries averaging 3% per year.

- The $10,000 remainder of the variance is related to an increase in cost of supplies and expenses none of which are material.

Explanation of Variance _ OPGC Contract Services

VARIANCE ANALYSIS		Variance [(6) - (1)]	% Change [(6) - (1)]	Variance [(6) - (4)]	% Change [(6) - (4)]
DISTRIBUTION EXPENSE PAID TO AFFILIATES:					
Orillia Power Generation - contract services		**81,000**	32.8%	20,000	6.5%

From 2006 Board Approved to the 2010 test year, there is an increase of $81,000 in contract services provided by OPGC. $44,000 of this increase is due to rising costs of maintenance of OPDC substations to meet regulatory requirements and replace aging infrastructure. The balance of $37,000 consists of increases in maintenance costs for the Control Centre, the Service Centre and some project management which individually are not material.

Explanation of Variance _ OPGC Power Purchased

VARIANCE ANALYSIS		Variance [(6) - (1)]	% Change [(6) - (1)]	Variance [(6) - (4)]	% Change [(6) - (4)]
DISTRIBUTION EXPENSE PAID TO AFFILIATES:					
Orillia Power Generation - power purchased		**(834,000)**	-100.0%	**(1,052,000)**	-100.0%

From 2006 Board Approved and 2008 Actual to the 2010 test year, there is a decrease in power purchased of $834,000 and $1,052,000, respectively. OPDC will no longer be purchasing power from OPGC beginning in 2010 as it expects to complete a connection from OPGC's Matthiasville plant directly into the Hydro One transmission system at the end of 2009.

Explanation of Variance _ City of Orillia

VARIANCE ANALYSIS		Variance [(6) - (1)]	% Change [(6) - (1)]	Variance [(6) - (4)]	% Change [(6) - (4)]
DISTRIBUTION EXPENSE PAID TO AFFILIATES:					
City of Orillia		**67,000**	54.5%	(5,000)	-2.6%

From 2006 Board Approved to the 2010 test year, there is an increase of $67,000 in contract services provided by the City of Orillia. Increase in the cost of fuel for vehicles and property taxes accounts for $39,000 of this increase. The balance of $26,000 relates to the cost of water, answering and call out services and miscellaneous services none of which is material.

OVERVIEW Purchase of Products and Services from Non-Affiliates:

OPDC purchases many services and products from third parties. Table 4-15 lists total purchases from non-affiliated companies exceeding $50,000 in any year from 2006 to 2008. Table 4-15 also summarizes total purchases from non-affiliated companies exceeding $25,000 for the first six months of 2009.

No projections of spending with suppliers have been provided for the last half of the Bridge Year and the Test Year. In some instances, such as with our billing service provider, OPDC has gone through a competitive bidding process and made a commitment to one supplier for a set period of time. For this type of service it is clearly beneficial to the organization and its customers to enter into a multi-year arrangement in order to obtain the best price and consistency of service. However, for most purchases, including inventory and contract construction services, OPDC has found it most cost effective to keep its options open, with a number of select, approved suppliers, to obtain the best possible price for goods and services, at the time they are required. Thus, it is impractical to list purchases from suppliers that have not happened yet.

OPDC's Expenditure Control Policy is included in Appendix 4-D. This policy provides a detailed and extensive framework that guides purchasing and expenditure decisions within the organization. In addition to addressing issues such as purchase order procedures, use of corporate credit cards and petty cash, the policy is focused on expenditure commitment processes and authority of staff at all levels to enter into any such commitments on behalf of the organization. OPDC believes that adherence to this policy provides strong internal controls and results in the best possible financial outcome for the organization and its customers.

Table 4-15: Purchases of Non-Affiliate Services

PURCHASE OF NON-AFFILIATE SERVICES AND PRODUCTS >$50,000 - 2006

Name	Activity	Priced by	2006 Dollars
Olameter Inc.	Billing, collection and meter reading services	RFP	417,000
S & C Electric Canada Ltd.	Switchgear supply and services	RFQ	238,000
Grafton Utility Supply Ltd.	Line hardware	RFQ	190,000
Hydro One	Load transfer customers - electricity	Sole source	138,000
Guelph Utility Pole Company Ltd.	Poles	RFQ	115,000
Noramco Wire & Cable	Wire	RFQ	94,000
Galloway Motors Ltd.	2007 Freightliner dump truck	Tender	92,000
Canada Post Corporation	Postage - customer bills	Sole source	89,000
The ITM Group Inc.	Network services and management	RFP	68,000
Hapamp Elmvale Ltd.	Excavation services/ Duct Installation	RFQ/Agreement/Tender	67,000
Barkley Technologies Inc.	System planning consulting services	Quote/Agreement	65,000
Storburn Construction Ltd.	Substation construction services	Tender	50,000

Dollars include all taxes including GST

For purposes of this report, removing GST would involve considerable more time and info would not be of greater value.

PURCHASE OF NON-AFFILIATE SERVICES AND PRODUCTS >$50,000 - 2007

Name	Activity	Priced by	2007 Dollars
Olameter Inc.	Billing, collection and meter reading services	RFP	438,000
Guelph Utility Pole Company Ltd.	Poles	RFQ	118,000
HD Supply Utilities	Line hardware	RFQ	117,000
Wallwin Electric Services Ltd.	Construction services	Tender	111,000
Noramco Wire & Cable	Wire	RFQ	95,000
Canada Post Corporation	Postage - customer bills	Sole source	79,000
The ITM Group Inc.	Network services and management	RFP	63,000
The Treeman	Tree trimming	Tender	59,000

Dollars include all taxes including GST

For purposes of this report, removing GST would involve considerable more time and info would not be of greater value.

Table 4-15: Purchases of Non-Affiliate Services (Continued)

PURCHASE OF NON-AFFILIATE SERVICES AND PRODUCTS >$50,000 - 2008

Name	Activity	Priced by	2008 Dollars
Olameter Inc.	Billing, collection and meter reading services	RFP	483,000
Wajax Industries Limited	2007 Freightliner utility vehicle	Tender	449,000
Survalent Technology Corp.	SCADA Master Station Hardware and Software	RFQ	234,000
HD Supply Utilities	Line hardware	RFQ	199,000
Storburn Construction Ltd.	Construction services	RFP/ Tender	196,000
Guelph Utility Pole Company Ltd.	Poles	RFQ	161,000
S & C Electric Canada Ltd.	Switchgear supply and services	RFQ	158,000
Moloney Electric Inc.	Transformer Supply	RFQ	85,000
Canada Post Corporation	Postage - customer bills	Sole source	85,000
Hapamp Elmvale Ltd.	Excavation services / Duct Installation	Quote/Agreement/Tender	67,000
Noramco Wire & Cable	Wire	RFQ	65,000
The ITM Group Inc.	Network services and management	RFP/ RFQ	56,000
Rogers Cable Inc.	Installation of ducts	Quote/Agreement	52,000
Joslyn Canada	Subtransmission line hardware	RFP	52,000
M3 & W Inc.	Turn Key Services 2008 OPA CDM Programs	RFP	51,000

Dollars include all taxes including GST

For purposes of this report, removing GST would involve considerable more time and info would not be of greater value.

PURCHASE OF NON-AFFILIATE SERVICES AND PRODUCTS >$25,000 - 2009 (First Six Months)

Name	Activity	Priced by	2009 Dollars
Olameter Inc.	Billing, collection and meter reading services	RFP	240,000
M3 & W Inc.	Turn Key Services 2009 OPA CDM Programs	RFP	189,000
KTI Limited	Smart Meter Collector	RFP/RFQ/Agreement	156,000
HD Supply Utilities	Line hardware	RFQ	130,000
Guelph Utility Pole Company Ltd.	Poles	RFQ	92,000
Davey Tree Expert Co. Limited	Tree trimming	Tender	90,000
S & C Electric Canada Ltd.	Switchgear	RFQ	89,000
Hapamp Elmvale Ltd.	Excavation services/ Duct Installation	Quote/Agreement/Tender	52,000
Canada Post Corporation	Postage - customer bills	Sole source	42,000
Asplundh Canada ULC	Tree trimming	Tender	33,000
Badger Daylighting Inc.	Hydrovac services	Quote/Agreement	32,000

Dollars include all taxes including GST

For purposes of this report, removing GST would involve considerable more time and info would not be of greater value.

DEPRECIATION ANALYSIS

Depreciation Expense in 2010 Test Year:

OPDC seeks to recover $1,449,000 of depreciation expense in the 2010 Test Year. As can be seen in Table 4-16, OPDC's depreciation expense is increasing year over year from 2006. Since 2006 depreciation expense has increased 6.8% ($92,800) or an average of 1.7% per year over four years.

The figures in Table 4-16 are the same figures in the fixed asset continuity schedules presented in Exhibit 2, Tab 2 Schedule 1 thus no reconciliation to those schedules is required.

OPDC's does not have a formal deprecation policy but does comply with the Accounting Procedures Handbook and the CICA handbook. A description of how OPDC accounts for depreciation follows in this schedule.

As required by section 2.5.7 of the OEB rate filing guidelines Appendix 2N of those guidelines has been completed for 2006 Actual through to 2010 Test and can be found in Exhibit 4, Tab 7, Schedule 2 as Tables 4-19 to 4-23. For 2010, OPDC has a variance of $29,000 between OPDC's calculation of deprecation and the calculation as required in Appendix 2N.

Table 4-16: Depreciation Expense Included in Revenue Requirement

Description		2006 Actual (1)	2007 Actual (2)	2008 Actual (3)	2009 Bridge (4)	2010 Test (5)
Distribution station equipment		90,800	92,300	90,700	95,000	93,000
Poles and wires		662,700	686,000	682,600	693,000	744,000
Line transformers		158,500	158,900	161,600	161,000	161,000
Services and meters		140,800	140,100	137,500	130,000	129,000
Land, land rights and buildings		43,800	45,700	62,000	37,000	36,000
Information technology		63,900	65,000	65,600	83,000	45,000
Equipment		182,800	127,200	191,200	205,000	220,000
Other distribution assets		12,900	2,900	16,000	25,000	21,000
TOTALS SUMMARY INFORMATION		**1,356,200**	**1,318,100**	**1,407,200**	**1,429,000**	**1,449,000**
1806	Land Rights	1,900	2,400	3,700	4,000	2,000
1820	Distribution Station Equipmen	90,800	92,300	90,700	95,000	93,000
1835	Overhead Conductors and De	458,600	476,400	488,500	496,000	536,000
1840	Underground Conduit	204,100	209,600	194,100	197,000	208,000
1850	Line Transformers	158,500	158,900	161,600	161,000	161,000
1855	Services	81,500	80,400	76,800	69,000	68,000
1860	Meters	59,300	59,700	60,700	61,000	61,000
1908	Buildings and Fixtures	41,900	43,300	58,300	33,000	34,000
1915	Office Furniture and Equipme	20,000	17,300	16,400	5,000	6,000
1920	Computer Equipment - Hardw	22,600	20,800	19,900	83,000	45,000
1925	Computer Software	41,300	44,200	45,700	-	-
1930	Transportation Equipment	118,200	72,900	141,400	173,000	187,000
1935	Stores Equipment	2,900	2,900	2,900	3,000	3,000
1940	Tools, Shop and Garage Equi	31,700	34,100	30,500	24,000	24,000
1960	Miscellaneous Equipment	10,000	-	-	-	-
1980	System Supervisory Equipme	27,800	14,700	34,000	25,000	21,000
1985	Sentinel Lighting	2,900	2,100	1,800	2,000	1,000
1995	Contributions and Grants	(14,900)	(11,800)	(18,000)	-	-
TOTALS DETAILED GENERAL LEDGER		**1,359,100**	**1,320,200**	**1,409,000**	**1,431,000**	**1,450,000**
1985	Sentinel Lighting Non LDC	2,900	2,100	1,800	2,000	1,000
TOTALS DETAILED LDC		**1,356,200**	**1,318,100**	**1,407,200**	**1,429,000**	**1,449,000**

Depreciation Expense INCREASING Before Next Rebasing Year 2014:

While OPDC recognizes that we would not be allowed to recover more than the 2010 Test amount, OPDC is concerned that it be allowed to recover at least the 2010 Test amount of $1,449,000. Depreciation expense has been calculated in a consistent fashion with the method used in the 2006 EDR and includes a full year of depreciation on current year additions. OPDC does not believe that using the half year rule for current year additions provides a better matching of costs with revenues in the long run given that useful life estimates are subject to their own margin of error.

Depreciation expense is expected to increase between 2010 and 2014 (next rebasing year after 2010). The level of capital expenditures required in order to maintain OPDC's aging infrastructure in good operating condition has been increasing over the last few years. These additions are adding more to depreciation expense than is dropping off due to assets becoming fully depreciated (disposals). Table 2-18 presented in Exhibit 2 is repeated here to illustrate the level of capital expenditures expected over the next few years.

Table 2-18: Capital Expenditure Plans from 2010 to 2015 Summarized By Project Drivers

Project Drivers	2010	2011	2012	2013	2014	2015
Aging Assets	1,305,000	2,056,000	838,000	1,418,000	1,770,000	1,765,000
Reliability	136,000	340,000	225,000	190,000	80,000	50,000
Growth / Customer Demand / Capacity	273,000	165,000	920,000	170,000	175,000	175,000
Totals	**$1,714,000**	**2,561,000**	**$1,983,000**	**$1,778,000**	**$2,025,000**	**$1,990,000**

A review of disposals (assets becoming fully depreciated) scheduled for the years 2011 through 2013 compared to projected capital spending indicates that this trend will continue. **It is expected that depreciation expense in 2011, 2012 and 2013 will be at levels HIGHER than the amount OPDC is seeking to recover in the 2010 Test Year**.

OPDC's financial planning model has detailed calculations for depreciation expense well beyond the next expected rebasing year of 2014. Excerpts from the planning model were presented in Appendix 1-G. Depreciation expense from 2008 through to 2013 shown on the model's Statement of Earnings has been listed in Table 4-17 below.

Table 4-17: Depreciation Expense from 2008 to 2013

Description	2008	2009	2010	2011	2012	2013
Depreciation Expense	1,409,000	1,431,000	1,450,000	1,495,000	1,497,000	1,523,000

Amortization Methods for Current Year Additions:

There is no prescriptive guidance in either the CICA Handbook or the OEB APH stating that only one half a year's depreciation should be taken on current year's additions. It is recognized that amortization should be determined in a rational and systematic manner appropriate to the nature of property, plant and equipment (with a limited life) and to its use by the enterprise.

The CICA Handbook requires that where prescriptive guidance is not given, professional judgment should always be used. The APH also states that **"*Consistent with the CICA Handbook, this APHandbook does not provide prescriptive guidance in terms of the amortization methods to be used, the asset categories, the estimated useful lives or amortization rates. Instead, it is expected that in the absence of an objective study to support changes to the current methods, lives or rates, utilities will continue to use methods, lives or rates consistent with past practice".***

There is certainly a margin of error surrounding useful life estimates for most assets, particularly when dealing with LDC assets that typically have long useful lives. Purely from a matching principle perspective, it is hard to argue that utilization of the half year rule provides a better matching than not. OPDC believes that it is reasonable, rational and systematic to take a full year of depreciation during the year of the addition on the asset and has consistently followed this method for many years.

Amortization Rates:

OPDC confirms that it has complied with the OEB's Accounting Procedures Handbook (APH) and the CICA Handbook with respect to the amortization of capital assets. In the absence of a current and objective industry study having been completed, OPDC continues to use useful lives, depreciation rates and methods accepted in the industry.

Table 4-18 summarizes the assets, useful life and deprecation rates utilized in OPDC's system.

Table 4-18: Depreciation Rates Based on Estimated Useful Life

	Description	Life Years	Rate
ESTIMATED USEFUL LIFE AND CORRESPONDING DEPRECATION RATE			
1806	Land Rights	5	20.0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	30	3.3%
1835	Overhead Conductors and Devices	25	4.0%
1840	Underground Conduit	25	4.0%
1850	Line Transformers	25	4.0%
1855	Services	25	4.0%
1860	Meters	25	4.0%
1905	Land	na	na
1908	Buildings and Fixtures	60	1.7%
1915	Office Furniture and Equipment	10	10.0%
1920	Computer Equipment - Hardware	5	20.0%
1925	Computer Software	5	20.0%
1930	Transportation Equipment (approximate effective average)	7	14.3%
1935	Stores Equipment	10	10.0%
1940	Tools, Shop and Garage Equipment	10	10.0%
1980	System Supervisory Equipment	15	6.7%
1985	Sentinel Lighting	10	10.0%
1995	Contributions and Grants	25	4.0%

Appendix 4-E is a copy of Appendix B of the 2006 Electricity Distribution Rate Handbook and summarizes the amortization rates to be used for electricity distributors. OPDC confirms that it utilizes these rates subject to the exceptions mentioned below:

- Certain building and fixtures acquired before 1992 are being amortized over 60 years versus the currently recommended 50-year period. Changes to this amortization period were put into effect on January 1, 1992. Assets affected were acquired prior to this change and will continue to be amortized at the rate prescribed at the time of acquisition.

- Certain underground conductors and devices acquired before 1986 are being amortized over 35 years versus the currently recommended 25-year period. Changes to this amortization period were mandated effective January 1, 1986 by the previous regulator, Ontario Hydro. Assets affected were acquired prior to this change and will continue to be amortized at the rate prescribed at the time of acquisition.

- Certain distribution meters acquired before 1986 are being amortized over 35 years versus the currently recommended 25-year period. Changes to this amortization period were mandated effective January 1, 1986 by the previous regulator, Ontario Hydro. Assets affected were acquired prior to this change and will continue to be amortized at the rate prescribed at the time of acquisition.

- Certain distribution transformers acquired before 1986 are being amortized over 30 years versus the currently recommended 25-year period. Changes to this amortization period were mandated effective January 1, 1986 by the previous regulator, Ontario Hydro. Assets affected were acquired prior to this change and will continue to be amortized at the rate prescribed at the time of acquisition.

- In 2008, OPDC made a significant investment its SCADA system. This involved a comprehensive upgrade to the hardware and software within the SCADA master station. Appendix B notes that assets in the System Supervisory Equipment category (GL 1980) are to be amortized straight line over 15 years. In light of the fact that this expenditure was exclusively for hardware and software (which is typically amortized over 5 years) and based on the professional judgement of OPDC staff, it is unrealistic to expect these assets to have a useful life of 15 years. OPDC has elected to amortize these assets over a period of 10 years, as it believes this is a more realistic life expectancy of these assets.

Grouped Assets vs Specific Identification:

For depreciation purposes, all like assets are grouped with the exception of computer equipment, software, automotive, major tools and SCADA Equipment. Depreciation is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year. In addition, OPDC's policy has always been to take a full year's amortization on capital additions during the current year.

Comments on Reconciliation Tables (Appendix 2N of Filing Guidelines):

Overhead Conductors and Devices (1835)

In certain years there is a noticeable variance between the depreciation taken by OPDC and the depreciation calculated using the prescribed rate. Given the substantial investments that are often undertaken in this category, the effect of the half year rule applied in the prescribed methodology versus the method utilized by OPDC can result in a noticeable variance in this account.

Transportation Equipment (1930)

Within this category, there are vehicles that are depreciated over a five year period and others that are depreciated over an eight year period. The classification is based upon vehicle weight and OPDC follows the guidelines per the accounting procedures handbook. For the purposes of the comparison in Table 2-17, OPDC used a subjective average depreciation period of seven years. As a result, in certain years, particularly those where a larger vehicle, subject to eight year amortization, was purchased, a variance was more noticeable.

Buildings and Fixtures (1908)

In certain years, there is a noticeable variance between the depreciation taken by OPDC and the depreciation calculated using the prescribed rate. In this category the variances can be explained due to the fact that capital expenditures on existing buildings may result in a betterment of the asset, without necessarily extending the useful life of the asset. In this scenario, an expenditure made in a particular year would be added to the value of the asset and amortized over the remaining useful life of the asset, which is shorter that the amortization period prescribed in the Accounting Procedures Handbook, yet still following proper accounting processes.

System Supervisory Equipment (1980)

The variance in this category is driven by OPDC's decision to amortize recent upgrades to its SCADA master station over a ten year period versus the prescribed fifteen year period. OPDC's rationale for this decision is noted in Exhibit 4, Tab 7, Schedule 1 but an excerpt is repeated here for ease of reading - 'In light of the fact that this expenditure was exclusively for hardware and software (which is typically amortized over 5 years) and based on the professional judgment of OPDC staff, it is unrealistic to expect these assets to have a useful life of 15 years. OPDC has elected to amortize these assets over a period of 10 years, as it believes this is a more realistic life expectancy of these assets, yet still remaining conservative, thereby resulting in amortization that will be recognized in a systematic and rational manner.'

Table 4-19: Depreciation Expense Calculation as Required Per Appendix 2-N of Filing Guidelines - 2010 Test

	Description	Gross Capital Cost	Less Fully Depreciated	Net For Depreciation	Current Additions	Available for Dep'n	Years	Depr'n Expense	OPDC Calculated	VARIANCE
DEPRECIATION EXPENSE COMPARISON FOR 2010 TEST										
1805	Land	134,000	0	134,000	0	134,000			0	**0**
1806	Land Rights	45,000	6,000	39,000	8,000	47,000	5	9,000	2,000	**7,000**
1820	Distribution Station Equipment - Normally Primary below 50	3,807,000	1,015,000	2,792,000	109,000	2,901,000	30	95,000	93,000	**2,000**
1835	Overhead Conductors and Devices	13,094,000	241,000	12,853,000	1,019,000	13,872,000	25	535,000	536,000	**(1,000)**
1840	Underground Conduit	4,872,000	0	4,872,000	281,000	5,153,000	25	201,000	208,000	**(7,000)**
1850	Line Transformers	4,201,000	0	4,201,000	45,000	4,246,000	25	169,000	161,000	**8,000**
1855	Services	1,878,000	83,000	1,795,000	60,000	1,855,000	25	73,000	68,000	**5,000**
1860	Meters	1,633,000	0	1,633,000	5,000	1,638,000	25	65,000	61,000	**4,000**
1905	Land	136,000	0	136,000	0	136,000			0	**0**
1908	Buildings and Fixtures	1,513,000	0	1,513,000	12,000	1,525,000	60	25,000	34,000	**(9,000)**
1915	Office Furniture and Equipment	49,000	2,000	47,000	10,000	57,000	10	5,000	6,000	**(1,000)**
1920	Computer Equipment - Hardware	133,000	67,000	66,000	25,000	91,000	5	16,000	45,000	**(29,000)**
1925	Computer Software	281,000	178,000	103,000	32,000	135,000	5	24,000	0	**24,000**
1930	Transportation Equipment	1,958,000	748,000	1,210,000	82,000	1,292,000	7	179,000	187,000	**(8,000)**
1935	Stores Equipment	29,000	0	29,000	0	29,000	10	3,000	3,000	**0**
1940	Tools, Shop and Garage Equipment	240,000	30,000	210,000	26,000	236,000	10	22,000	24,000	**(2,000)**
1980	System Supervisory Equipment	1,755,000	1,540,000	215,000	0	215,000	15	14,000	21,000	**(7,000)**
1985	Sentinel Lighting	16,000	4,000	12,000	0	12,000	10	1,000	1,000	**0**
1995	Contributions and Grants	(371,000)	0	(371,000)	0	(371,000)	25	(15,000)	0	**(15,000)**
		35,403,000	**3,914,000**	**31,489,000**	**1,714,000**	**33,203,000**	**317**	**1,421,000**	**1,450,000**	**(29,000)**
1985	Sentinel Lighting Non LDC	16,000	4,000	12,000	0	12,000	10	1,000	1,000	**0**
		35,387,000	**3,910,000**	**31,477,000**	**1,714,000**	**33,191,000**	**307**	**1,420,000**	**1,449,000**	**(29,000)**

Table 4-20: Depreciation Expense Calculation as Required Per Appendix 2-N of Filing Guidelines - 2009 Bridge

Description		Gross Capital Cost	Less Fully Depreciated	Net For Depreciation	Current Additions	Available for Dep'n	Years	Depr'n Expense	OPDC Calculated	VARIANCE
DEPRECIATION EXPENSE COMPARISON FOR 2009 BRIDGE										
1805	Land	74,000	0	74,000	60,000	134,000			0	**0**
1806	Land Rights	37,000	19,000	18,000	8,000	26,000	5	4,000	4,000	**0**
1820	Distribution Station Equipment - Normally Primary below 50	3,688,000	868,000	2,820,000	119,000	2,939,000	30	96,000	95,000	**1,000**
1835	Overhead Conductors and Devices	12,106,000	0	12,106,000	988,000	13,094,000	25	504,000	496,000	**8,000**
1840	Underground Conduit	4,662,000	0	4,662,000	210,000	4,872,000	25	191,000	197,000	**(6,000)**
1850	Line Transformers	4,146,000	0	4,146,000	55,000	4,201,000	25	167,000	161,000	**6,000**
1855	Services	1,819,000	0	1,819,000	59,000	1,878,000	25	74,000	69,000	**5,000**
1860	Meters	1,623,000	0	1,623,000	10,000	1,633,000	25	65,000	61,000	**4,000**
1905	Land	136,000	0	136,000	0	136,000			0	**0**
1908	Buildings and Fixtures	1,445,000	55,000	1,390,000	68,000	1,458,000	60	24,000	33,000	**(9,000)**
1915	Office Furniture and Equipment	44,000	0	44,000	5,000	49,000	10	5,000	5,000	**0**
1920	Computer Equipment - Hardware	98,000	0	98,000	35,000	133,000	5	23,000	83,000	**(60,000)**
1925	Computer Software	228,000	0	228,000	53,000	281,000	5	51,000	0	**51,000**
1930	Transportation Equipment	1,708,000	718,000	990,000	250,000	1,240,000	7	159,000	173,000	**(14,000)**
1935	Stores Equipment	29,000	0	29,000	0	29,000	10	3,000	3,000	**0**
1940	Tools, Shop and Garage Equipment	214,000	0	214,000	26,000	240,000	10	23,000	24,000	**(1,000)**
1980	System Supervisory Equipment	1,755,000	1,509,000	246,000	0	246,000	15	16,000	25,000	**(9,000)**
1985	Sentinel Lighting	16,000	4,000	12,000	0	12,000	10	1,000	2,000	**(1,000)**
1995	Contributions and Grants	(371,000)	0	(371,000)	0	(371,000)	25	(15,000)	0	**(15,000)**
		33,457,000	**3,173,000**	**30,284,000**	**1,946,000**	**32,230,000**	**317**	**1,391,000**	**1,431,000**	**(40,000)**
1985	Sentinel Lighting Non LDC	16,000	4,000	12,000	0	12,000	10	1,000	2,000	**(1,000)**
		33,441,000	**3,169,000**	**30,272,000**	**1,946,000**	**32,218,000**	**307**	**1,390,000**	**1,429,000**	**(39,000)**

Table 4-21: Depreciation Expense Calculation as Required Per Appendix 2-N of Filing Guidelines - 2008 Actual

Description		Gross Capital Cost	Less Fully Depreciated	Net For Depreciation	Current Additions	Available for Dep'n	Years	Depr'n Expense	OPDC Calculated	VARIANCE
DEPRECIATION EXPENSE COMPARISON FOR 2008 ACTUAL										
1805	Land	0	0	0	74,100	74,100			0	
1806	Land Rights	30,900	19,000	11,900	6,300	18,200	5	3,000	3,700	**(700)**
1820	Distribution Station Equipment - Normally Primary below 50	3,757,500	990,000	2,767,500	52,200	2,819,700	30	93,000	90,700	**2,300**
1835	Overhead Conductors and Devices	12,253,300	1,179,000	11,074,300	1,253,900	12,328,200	25	468,000	488,500	**(20,500)**
1840	Underground Conduit	5,121,500	674,000	4,447,500	215,100	4,662,600	25	182,000	194,100	**(12,100)**
1850	Line Transformers	4,077,000	0	4,077,000	68,900	4,145,900	25	164,000	161,600	**2,400**
1855	Services	2,198,200	311,000	1,887,200	31,700	1,918,900	25	76,000	76,800	**(800)**
1860	Meters	2,016,800	419,000	1,597,800	25,300	1,623,100	25	64,000	60,700	**3,300**
1905	Land	206,200	0	206,200	(70,500)	135,700			0	
1908	Buildings and Fixtures	1,232,400	55,000	1,177,400	226,900	1,404,300	60	22,000	58,300	**(36,300)**
1915	Office Furniture and Equipment	399,800	237,000	162,800	1,600	164,400	10	16,000	16,400	**(400)**
1920	Computer Equipment - Hardware	595,700	503,000	92,700	6,800	99,500	5	19,000	19,900	**(900)**
1925	Computer Software	622,200	404,000	218,200	10,600	228,800	5	45,000	45,700	**(700)**
1930	Transportation Equipment	1,699,800	1,231,000	468,800	520,900	989,700	7	104,000	141,400	**(37,400)**
1935	Stores Equipment	35,600	7,000	28,600	0	28,600	10	3,000	2,900	**100**
1940	Tools, Shop and Garage Equipment	582,700	317,000	265,700	38,800	304,500	10	29,000	30,500	**(1,500)**
1980	System Supervisory Equipment	1,925,200	1,793,000	132,200	207,700	339,900	15	16,000	34,000	**(18,000)**
1985	Sentinel Lighting	125,200	108,000	17,200	0	17,200	10	2,000	1,800	**200**
1995	Contributions and Grants	(371,400)	0	(371,400)	0	(371,400)	25	(15,000)	(18,000)	**3,000**
		36,927,300	**8,247,000**	**28,680,300**	**2,251,600**	**30,931,900**	**317**	**1,291,000**	**1,409,000**	**(118,000)**
1985	Sentinel Lighting Non LDC	125,200	108,000	17,200	0	17,200	10	2,000	1,800	**200**
		36,802,100	**8,139,000**	**28,663,100**	**2,251,600**	**30,914,700**	**307**	**1,289,000**	**1,407,200**	**(118,200)**

Table 4-22: Depreciation Expense Calculation as Required Per Appendix 2-N of Filing Guidelines - 2007 Actual

Description		Gross Capital Cost	Less Fully Depreciated	Net For Depreciation	Current Additions	Available for Dep'n	Years	Depr'n Expense	OPDC Calculated	VARIANCE
DEPRECIATION EXPENSE COMPARISON FOR 2007 ACTUAL										
1805	Land	0	0	0	0	0			0	
1806	Land Rights	25,400	16,000	9,400	5,500	14,900	5	2,000	2,400	**(400)**
1820	Distribution Station Equipment - Normally Primary below 50	3,671,700	850,000	2,821,700	85,800	2,907,500	30	95,000	92,300	**2,700**
1835	Overhead Conductors and Devices	11,539,600	893,000	10,646,600	713,700	11,360,300	25	440,000	476,400	**(36,400)**
1840	Underground Conduit	4,983,300	0	4,983,300	138,100	5,121,400	25	202,000	209,600	**(7,600)**
1850	Line Transformers	4,067,900	0	4,067,900	9,100	4,077,000	25	163,000	158,900	**4,100**
1855	Services	2,169,800	189,000	1,980,800	28,400	2,009,200	25	80,000	80,400	**(400)**
1860	Meters	2,008,700	419,000	1,589,700	8,100	1,597,800	25	64,000	59,700	**4,300**
1905	Land	189,100	0	189,100	17,100	206,200			0	
1908	Buildings and Fixtures	1,194,900	55,000	1,139,900	37,500	1,177,400	60	19,000	43,300	**(24,300)**
1915	Office Furniture and Equipment	396,600	196,000	200,600	3,200	203,800	10	20,000	17,300	**2,700**
1920	Computer Equipment - Hardware	583,100	492,000	91,100	12,600	103,700	5	19,000	20,800	**(1,800)**
1925	Computer Software	607,700	401,000	206,700	14,500	221,200	5	43,000	44,200	**(1,200)**
1930	Transportation Equipment	1,688,900	1,251,000	437,900	31,000	468,900	7	65,000	72,900	**(7,900)**
1935	Stores Equipment	35,600	7,000	28,600	0	28,600	10	3,000	2,900	**100**
1940	Tools, Shop and Garage Equipment	545,400	242,000	303,400	37,400	340,800	10	32,000	34,100	**(2,100)**
1980	System Supervisory Equipment	1,925,200	1,778,000	147,200	0	147,200	15	10,000	14,700	**(4,700)**
1985	Sentinel Lighting	131,400	49,000	82,400	1,700	84,100	10	8,000	2,100	**5,900**
1995	Contributions and Grants	(371,400)	0	(371,400)	0	(371,400)	25	(15,000)	(11,800)	**(3,200)**
		35,790,000	**6,838,000**	**28,952,000**	**1,165,300**	**30,117,300**	**317**	**1,250,000**	**1,320,200**	**(70,200)**
1985	Sentinel Lighting Non LDC	131,400	49,000	82,400	1,700	84,100	10	8,000	2,100	**5,900**
		35,658,600	**6,789,000**	**28,869,600**	**1,163,600**	**30,033,200**	**307**	**1,242,000**	**1,318,100**	**(76,100)**

Table 4-23: Depreciation Expense Calculation as Required Per Appendix 2-N of Filing Guidelines - 2006 Actual

Description		Gross Capital Cost	Less Fully Depreciated	Net For Depreciation	Current Additions	Available for Dep'n	Years	Depr'n Expense	OPDC Calculated	VARIANCE
DEPRECIATION EXPENSE COMPARISON FOR 2006 ACTUAL										
1805	Land	0	0	0	0	0			0	
1806	Land Rights	24,900	16,000	8,900	500	9,400	5	2,000	1,900	**100**
1820	Distribution Station Equipment - Normally Primary below 50	3,181,700	825,000	2,356,700	490,000	2,846,700	30	87,000	90,800	**(3,800)**
1835	Overhead Conductors and Devices	11,110,700	676,000	10,434,700	502,300	10,937,000	25	427,000	458,600	**(31,600)**
1840	Underground Conduit	4,669,800	0	4,669,800	313,600	4,983,400	25	193,000	204,100	**(11,100)**
1850	Line Transformers	4,060,800	0	4,060,800	7,100	4,067,900	25	163,000	158,500	**4,500**
1855	Services	2,063,100	131,000	1,932,100	106,600	2,038,700	25	79,000	81,500	**(2,500)**
1860	Meters	1,964,600	417,000	1,547,600	44,100	1,591,700	25	63,000	59,300	**3,700**
1905	Land	189,100	0	189,100	0	189,100			0	
1908	Buildings and Fixtures	1,154,500	55,000	1,099,500	40,400	1,139,900	60	19,000	41,900	**(22,900)**
1915	Office Furniture and Equipment	379,600	192,000	187,600	17,000	204,600	10	20,000	20,000	**0**
1920	Computer Equipment - Hardware	571,300	470,000	101,300	11,700	113,000	5	21,000	22,600	**(1,600)**
1925	Computer Software	582,600	401,000	181,600	25,100	206,700	5	39,000	41,300	**(2,300)**
1930	Transportation Equipment	1,621,600	891,000	730,600	129,900	860,500	7	114,000	118,200	**(4,200)**
1935	Stores Equipment	35,600	7,000	28,600	0	28,600	10	3,000	2,900	**100**
1940	Tools, Shop and Garage Equipment	520,900	228,000	292,900	24,500	317,400	10	31,000	31,700	**(700)**
1980	System Supervisory Equipment	1,925,200	1,647,000	278,200	0	278,200	15	19,000	27,800	**(8,800)**
1985	Sentinel Lighting	131,700	49,000	82,700	(300)	82,400	10	8,000	2,900	**5,100**
1995	Contributions and Grants	(211,400)	0	(211,400)	(160,000)	(371,400)	25	(12,000)	(14,900)	**2,900**
		34,702,400	**6,005,000**	**28,697,400**	**1,552,500**	**30,249,900**	**317**	**1,276,000**	**1,359,100**	**(73,100)**
1985	Sentinel Lighting Non LDC	131,700	49,000	82,700	(300)	82,400	10	8,000	2,900	**5,100**
		34,570,700	**5,956,000**	**28,614,700**	**1,552,800**	**30,167,500**	**307**	**1,268,000**	**1,356,200**	**(78,200)**

TAX CALCULATIONS:

OPDC is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. A copy of the 2008 Federal T2 and Ontario C23 tax return has been provided in Appendix 4-F.

OPDC's detailed tax calculations using the most recent tax rates are provided in the following Tables 4-24 through to 4-27.

Table 4-24: Schedule of Taxable Income and Summary of Income and Capital Taxes

Description	2006 EDR (1)	2009 Bridge (2)	2010 Test (3)
CALCULATION OF INCOME TAXES			
Accounting Income	815,200	202,500	967,000
Tax Adjustments to Accounting Income	307,300	6,600	68,300
Taxable Income	1,122,500	209,100	1,035,300
Combined Effective Income Tax Rate	35.7%	24.5%	29.2%
Total Income Taxes	**400,900**	**51,200**	**302,400**
SUMMARY OF INCOME AND CAPITAL TAXES			
Income Taxes - Federal	247,000	39,700	186,400
Income Taxes - Provincial	153,900	11,500	116,000
Total Income Taxes	**400,900**	**51,200**	**302,400**
Reduction in PILs due to error in 2006 PILs model	(57,100)		
Capital Tax - Provincial	50,400	17,600	6,000
Total Taxes	**394,200**	**68,800**	**308,400**

Table 4-25: Schedule of Tax Rates

Description	2006 EDR (1)	2009 Bridge (2)	2010 Test (3)
Federal Income Tax Rates			
Base rate less federal tax abatement	29.00%	28.00%	28.00%
General Tax Reduction for CCPCs	7.00%	9.00%	10.00%
Net Federal Income Tax Rate	**22.00%**	**19.00%**	**18.00%**
Provincial Income Tax Rates			
On the first $500,000 of taxable income	5.50%	5.50%	5.00%
On the next $1000,000 clawback of SBD	18.25%	18.25%	17.00%
Effective Ontario tax rate at $1.5 million of taxable income	**13.73%**	**14.00%**	**13.00%**

Table 4-26: Schedule of Adjustments to Income For Income Tax Purposes

Description	2006 EDR (1)	2009 Bridge (2)	2010 Test (3)
Income Tax Adjustments - Additions to net income for tax purposes			
Interest and penalties on taxes	3,700	-	-
Amortization of tangible assets	1,265,600	1,429,000	1,449,000
Income or loss for tax purposes- joint ventures or partnerships	3,600	-	-
Loss on disposal of assets	44,400	-	-
Charitable donations - Schedule 2	23,000	20,000	20,000
Non-deductible meals and entertainment expense	3,900	8,000	8,000
Tax reserves beginning of year	-	-	-
Accounting Reserves not deductable for tax purposes - end of year	110,000	1,103,600	1,103,600
Other Additions	-	-	-
Total Additions	**1,454,200**	**2,560,600**	**2,580,600**
Income Tax Adjustments - Reductions to net income for tax purposes			
Gain on disposal of assets per financial statements	14,000	-	-
Capital cost allowance from Schedule 8	912,300	1,429,200	1,387,100
Cumulative eligible capital deduction from Schedule 10	-	1,200	1,600
Tax reserves end of year from Schedule 13	-	-	-
Accounting Reserves not deductable for tax purposes - beginning of year	110,000	1,103,600	1,103,600
Other Deductions	87,600	-	-
Total Reductions	**1,123,900**	**2,534,000**	**2,492,300**
Other Adjustments			
Charitable donations from Schedule 2	(23,000)	(20,000)	(20,000)
Total Adjustments	**(23,000)**	**(20,000)**	**(20,000)**
Tax Adjustments to Accounting Income	**307,300**	**6,600**	**68,300**

Table 4-27: Detailed Tax Calculations

Description	2006 EDR (1)	2009 Bridge (2)	2010 Test (3)
FEDERAL PAYMENTS IN LIEU OF INCOME TAXES (PILS) CALCUATIONS			
Accounting Income	815,200	202,500	967,000
Tax Adjustments to Accounting Income	307,300	6,600	68,300
Taxable Income	**1,122,500**	**209,100**	**1,035,300**
Effective Federal Income Tax Rates on taxable income	22.00%	19.00%	18.00%
Federal Income Tax Expense	**247,000**	**39,700**	**186,400**
PROVINCIAL PAYMENTS IN LIEU OF INCOME TAXES (PILS) CALCUATIONS			
Taxable income up to the SBD Threshold	400,000	209,100	500,000
Taxable income subject to clawback of SBD	722,500	-	535,300
Taxable income over $1,500,000	-	-	-
Taxable Income - Total	**1,122,500**	**209,100**	**1,035,300**
Tax rate on the first $500,000 of taxable income	5.50%	5.50%	5.00%
Tax rate on the next $1000,000 of taxable income (clawback of SBD)	18.25%	18.25%	17.00%
Tax rate after $1,500,000 of taxable income	13.73%	14.00%	13.00%
Taxes on the first $500,000 of taxable income	22,000	11,500	25,000
Taxes on the next $1000,000 of taxable income (clawback of SBD)	131,900	-	91,000
Taxes after $1,500,000 of taxable income	-	-	-
Provincial Income Tax Expense	**153,900**	**11,500**	**116,000**
Effective Provincial Income Tax Rates on taxable income	13.71%	5.50%	11.20%
COMBINED PAYMENTS IN LIEU OF INCOME TAXES (PILS)			
Federal Income Tax Expense	247,000	39,700	186,400
Provincial Income Tax Expense	153,900	11,500	116,000
Combined Income Tax Expense	**400,900**	**51,200**	**302,400**
Effective Combined Tax Rate	35.7%	24.5%	29.2%
CAPITAL TAX CALCULATIONS			
Total Rate Base (for 2006 taxable capital different than rate base)	16,804,500	20,227,700	20,743,200
Portion of exemption utilized by LDC		12,402,000	12,452,000
Deemed Taxable Capital	16,804,500	7,825,700	8,291,200
Capital Tax Rates	0.300%	0.225%	0.075%
Ontario Capital Tax - Deemed	**50,400**	**17,600**	**6,200**

TAX SCHEDULES:

OPDC'S calculation of capital cost allowance is outlined below in the CCA continuity schedules.

Table 4-28: T2 Schedule 8 - CCA Continuity Schedule - 2010 Test

Class	Class Description	(1) UCC Start of year	(2) Cost of Additions	(3) Proceeds of disposition	(4) Adjustment for Additions 50% of Col (2) - (3)	(5) Base Amount for CCA [(1) + (4)]	(6) Rate %	(7) CCA [(5) x (6)]	(8) UCC Ending Balance
1	**Distribution System - 1988 to 22-Feb-2005**	14,909,842	0	0	0	14,909,842	4%	596,394	14,313,448
3	**Buildings**	890,078	12,000	0	6,000	896,078	5%	44,804	857,274
8	**General Office Equipment**	214,865	36,000	0	18,000	232,865	20%	46,573	204,292
10	**Transportation Equipment / Computers pre 2004**	659,484	82,000	0	41,000	700,484	30%	210,145	531,339
12	**Computer Software**	26,500	32,000	0	16,000	42,500	100%	42,500	16,000
45	**Computers & Systems Hardware acq'd post Mar 22/04**	3,407	0	0	0	3,407	45%	1,533	1,874
46	**Data Network Infrastructure Eq (acq'd post Mar 22/04)**	10,354	0	0	0	10,354	30%	3,106	7,248
47	**Distribution System - post 22-Feb-2005**	4,480,743	1,519,000	0	759,500	5,240,243	8%	419,219	5,580,524
50	**Computers & Systems Hardware acq'd post Mar 19/07**	29,090	25,000	0	12,500	41,590	55%	22,875	31,215
		21,224,363	**1,706,000**	**0**	**853,000**	**22,077,363**		**1,387,149**	**21,543,214**

Table 4-29: T2 Schedule 8 - CCA Continuity Schedule - 2009 Bridge

Class	Class Description	(1) UCC Start of year	(2) Cost of Additions	(3) Proceeds of disposition	(4) Adjustment for Additions 50% of Col (2) - (3)	(5) Base Amount for CCA [(1) + (4)]	(6) Rate %	(7) CCA [(5) x (6)]	(8) UCC Ending Balance
1	**Distribution System - 1988 to 22-Feb-2005**	15,531,085	0	0	0	15,531,085	4%	621,243	14,909,842
3	**Buildings**	867,135	68,000	0	34,000	901,135	5%	45,057	890,078
8	**General Office Equipment**	233,706	31,000	0	15,500	249,206	20%	49,841	214,865
10	**Transportation Equipment / Computers pre 2004**	638,548	250,000	0	125,000	763,548	30%	229,064	659,484
12	**Computer Software**	109,165	53,000	0	26,500	135,665	100%	135,665	26,500
45	**Computers & Systems Hardware acq'd post Mar 22/04**	6,194	0	0	0	6,194	45%	2,787	3,407
46	**Data Network Infrastructure Eq (acq'd post Mar 22/04)**	14,791	0	0	0	14,791	30%	4,437	10,354
47	**Distribution System - post 22-Feb-2005**	3,366,721	1,441,000	0	720,500	4,087,221	8%	326,978	4,480,743
50	**Computers & Systems Hardware acq'd post Mar 19/07**	8,256	35,000	0	17,500	25,756	55%	14,166	29,090
		20,775,601	**1,878,000**	**0**	**939,000**	**21,714,601**		**1,429,238**	**21,224,363**

Table 4-30: T2 Schedule 8 - CCA Continuity Schedule - 2008 Actual

Class	Class Description	(1) UCC Start of year	(2) Cost of Additions	(3) Proceeds of disposition	(4) Adjustment for Additions 50% of Col (2) - (3)	(5) Base Amount for CCA [(1) + (4)]	(6) Rate %	(7) CCA [(5) x (6)]	(8) UCC Ending Balance
1	**Distribution System - 1988 to 22-Feb-2005**	15,946,577	226,909	0	113,455	16,060,032	4%	642,401	15,531,085
3	**Buildings**	912,774	0	0	0	912,774	5%	45,639	867,135
8	**General Office Equipment**	246,635	40,442	0	20,221	266,856	20%	53,371	233,706
10	**Transportation Equipment / Computers pre 2004**	292,644	520,887	(10,655)	255,116	547,760	30%	164,328	638,548
12	**Computer Software**	7,270	218,330	0	109,165	116,435	100%	116,435	109,165
45	**Computers & Systems Hardware acq'd post Mar 22/04**	11,262	0	0	0	11,262	45%	5,068	6,194
46	**Data Network Infrastructure Eq (acq'd post Mar 22/04)**	21,130	0	0	0	21,130	30%	6,339	14,791
47	**Distribution System - post 22-Feb-2005**	2,369,903	1,235,844	0	617,922	2,987,825	8%	239,026	3,366,721
50	**Computers & Systems Hardware acq'd post Mar 19/07**	7,434	6,774	0	3,387	10,821	55%	5,952	8,256
		19,815,629	**2,249,186**	**(10,655)**	**1,119,266**	**20,934,895**		**1,278,559**	**20,775,601**

Table 4-31: Schedule 10 - CEC Continuity Schedule 2008 to 2010

Schedule 10 - CEC Continuity Schedule	(4) 2008 Actual	(5) 2009 Bridge	(6) 2010 Test
Balance at beginning of year			
Cumulative Eligible Capital at Beginning of year _ Land Rights	7,901	11,772	16,528
Additions:			
Cost of Eligible Capital Property Acquired during the year	6,342	8,000	8,000
Other Adjustments		-	
Subtotal	6,342	8,000	8,000
	x 3/4 =	x 3/4 =	x 3/4 =
Eligible portion for write-off	**4,757**	**6,000**	**6,000**
Deductions:			
Cost of Eligible Capital Property Disposed of during the year	-	-	-
Other Adjustments	-	-	-
Subtotal	-	-	-
	x 3/4 =	x 3/4 =	x 3/4 =
Reduction in portion for write off	**-**	**-**	**-**
CEC Deduction			
Amount available for write off in current year	12,658	17,772	22,528
	7%	7%	7%
CEC Deduction for year	**886**	**1,244**	**1,577**
Balance at beginning of year			
Cumulative Eligible Capital - Closing Balance	11,772	16,528	20,951

APPENDIX 4 – A

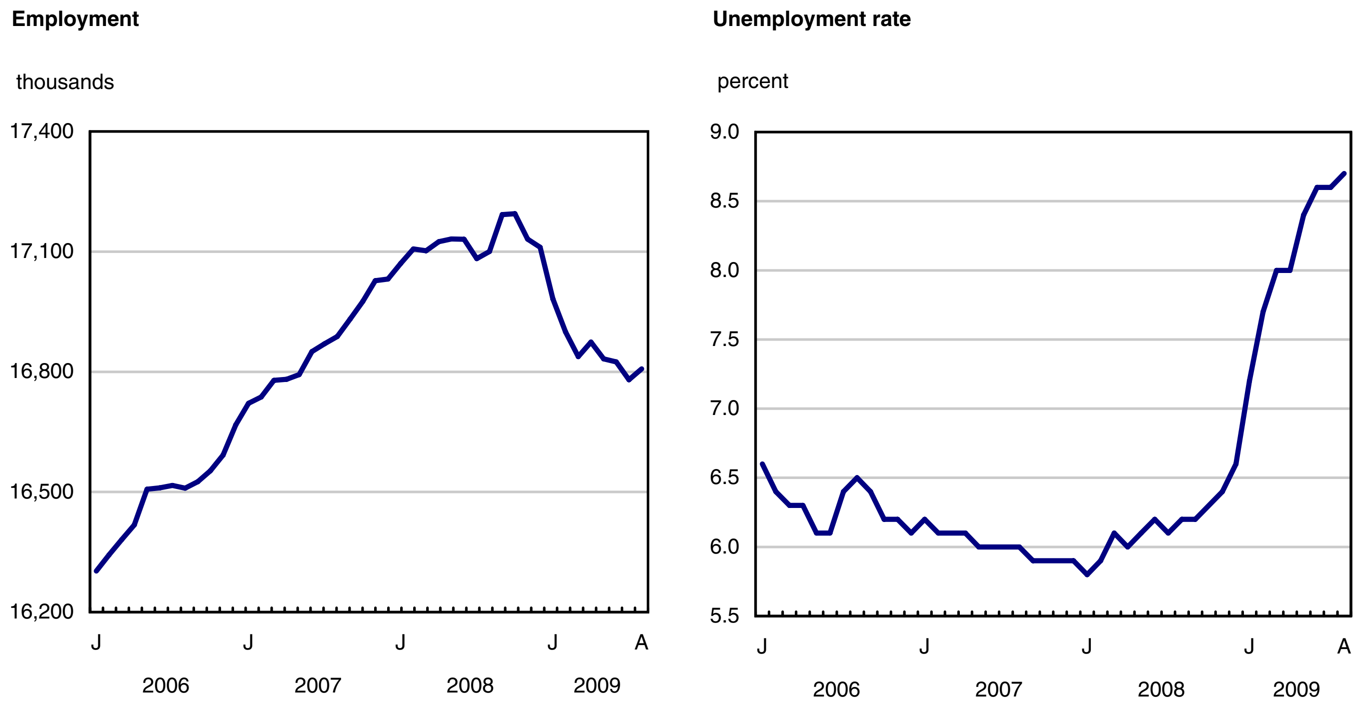
A copy of various statistics and articles concerning the current economic conditions in Ontario and the City of Orillia follows on the next 11 pages.

Highlights

August 2009

Employment increased by 27,000 in August, led by part-time work and among private sector employees. The unemployment rate edged up 0.1 percentage points to 8.7% as more people participated in the labour market.

Chart 1
Employment and unemployment rates, Canada, seasonally adjusted



Related tables: Merchandise exports, Residential construction, Financial statements and performance, Employment and unemployment, Monetary authorities, Leading indicators, Consumer price indexes, Housing and dwelling characteristics, Retail sales by type of store.

Economic indicators, by province and territory (monthly and quarterly)
(Ontario)

	Most recent period		Change from previous period	Change from previous yea
			%	
Ont.				
Labour market				
Employment *(SA, thousands)*	August 2009	**6,512.5**	0.2	-2.
			percentage points	
Unemployment rate *(SA, %)*	August 2009	**9.4**	0.1	3.
Participation rate *(SA, %)*	August 2009	**67.3**	0.1	-0.
			%	
Labour income *(SA, $ millions)*	June 2009	**26,988.7**	-1.0	-2.
Average weekly earnings *(SA, $)*	June 2009	**843.43**	0.04	0.6
Source: Statistics Canada, CANSIM, tables (for fee) 277-0001, 277-0002, 281-0028, 382-0006 and 282-0087.				
Prices				
			%	
Consumer price index *(2002=100)*	July 2009	**113.7**	-0.4	-1.
Source: Statistics Canada, CANSIM, table (for fee) 326-0020.				
Demand				
			%	
Retail trade (SA, $ millions)	June 2009	**12,229.6**	0.1	-4.
Source: Statistics Canada, CANSIM, table (for fee) 080-0014.				
Manufacturing				
			%	
Sales (SA, $ million)	June 2009	**17,340.6**	-0.3	-27.
Source: Statistics Canada, CANSIM, table (for fee) 304-0015.				
Residential construction				
			%	
Building permits *(SA, $ million)*	July 2009	**1,374.9**	-27.5	-38.
Housing starts *(SAAR, thousands of units)*	August 2009	**44.2**	13.0	-51.

SA - seasonally adjusted
SAAR - seasonally adjusted at annual rates
Source: Statistics Canada, CANSIM, tables (for fee) 026-0006 and 027-0007.
Last Modified: 2009-09-09.

Find information related to this table (CANSIM table(s); Definitions, data sources and methods; *The Daily*; publications; and relate Summary tables).

Date Modified: 2009-09-09

Pick a Province Pick an Indicator

Ontario Unemployment rate Display Indicator Data

Ontario, Unemployment rate

The unemployment rate represents the number of unemployed persons expressed as a percentage of the labour force. The unemployment rate for a particular age–sex group is the number unemployed in that group expressed as a percentage of the labour force for that group. Data for the provinces come from CANSIM table 282-0087.

Both sexes, 15 years and over

Seasonally adjusted

%

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1998								6.9	7.0	6.9	7.0	7.0
1999	6.6	6.7	6.6	7.2	6.9	6.3	6.4	5.9	6.3	5.8	5.6	5.5
2000	5.7	5.8	5.7	5.6	5.6	5.6	5.4	5.9	5.9	5.9	6.0	6.0
2001	5.8	6.2	6.2	6.1	5.9	6.1	6.4	6.4	6.5	6.6	6.9	7.0
2002	7.6	7.1	7.2	7.1	7.0	7.0	7.0	7.1	7.1	7.1	6.8	7.0
2003	6.9	6.8	6.5	6.9	7.1	7.2	7.1	6.9	7.3	7.0	6.9	6.7
2004	6.7	6.7	6.9	6.8	7.0	6.9	6.7	6.8	6.5	6.6	6.8	6.9
2005	6.6	6.9	6.9	6.7	6.9	6.8	6.6	6.6	6.5	6.5	6.0	6.3
2006	6.5	6.3	6.1	6.2	5.9	6.0	6.4	6.5	6.7	6.5	6.4	6.0
2007	6.5	6.4	6.5	6.6	6.3	6.5	6.6	6.5	6.3	6.2	6.3	6.4
2008	6.3	6.1	6.4	6.3	6.4	6.7	6.4	6.4	6.5	6.7	7.1	7.2
2009	8.0	8.7	8.7	8.7	9.4	9.6						

Source: Statistics Canada
www.statcan.gc.ca

CSV (Comma-Separated Values), table format Download Now

The state of Canadian household debt in a stumbling economy

May 27, 2009

In the winter of 2008, the Certified General Accountants Association of Canada (CGA-Canada) embarked on a second consumer survey on the topic of household debt and consumption in Canada. A similar survey was commissioned by CGA-Canada in the spring of 2007. The purpose of this particular survey seeks to understand the extent to which the economic and financial crisis worsened financial positions of Canadians having already experienced some financial strains. As we have seen, the topic of household debt and consumption is timely, relevant and critical for Canadians to consider.

We anticipate that this new report entitled *Where Has the Money Gone: The State of Canadian Household Debt in a Stumbling Economy*, will be of significant value to the Canadian public.

Key Report Highlights

Increasing debt load

- Household debt is at an all-time high reaching $1.3 trillion in 2008 and the escalation of debt is primarily caused by consumption motives rather than asset accumulation.
- The three main indicators of household indebtedness (debt-to-income, debt-to-assets and debt-to-net worth ratios) deteriorated significantly in the past two years and particularly during 2008.
- Canadian households are financing consumption activity and fuelling gross domestic product growth with unearned money as families increasingly reach for credit to finance day-to-day living expenses.
- The majority (58%) of survey respondents with rising debt said that day-to-day living expenses are the main cause for the increasing debt. This was higher than the 52% reported in 2007.
- Lines of credit and credit cards account for the largest proportion of consumer debt, with 85% of indebted Canadians reporting that they have outstanding debt on a credit card.
- A large proportion of Canadians acknowledged their debt as increasing. The proportion of respondents with rising debt went up from 35% in 2007 to 42% in 2008.
- 84% (vs. 81% in 2007) of Canadians are concerned that household debt is rising. 21% of Canadians who are in debt say they are in over their heads and can no longer manage their debt load.
- Interestingly enough though, 79% of indebted Canadians are still confident that they can either manage their debt well or take on more debt load.
- The majority of respondents (65%) felt that debt limits their ability to reach financial goals in at least one of the critical areas of retirement, education, leisure and travel, or financial security in unexpected circumstances.

Lack of savings

- One third of Canadians do not commit any resources to savings and deteriorating economic conditions have not yet had the usual effect of encouraging increased savings.
- Even with the temporary relief of a credit card or line of credit, one quarter of Canadians would not be able to handle an unforeseen expenditure of $5,000 and 1 in 10 would face difficulty in dealing with $500 unforeseen expense.
- The majority (78%) of surveyed said they would not change their saving patterns in order to build or rebuild the financial cushion.

Economic factors

- The Canadian economy has been recession free for 17 years before the events of 2008. The most recent recession took place over a 12 month period between April 1990 and March 1991.
- Recent data on the job losses and bankruptcies leaves little doubt that the situation of the household sector has worsened.
- Canadians, though, perceive their financial condition to be better than it is and many are not aware of how the economic downturn has impacted their financial situation.
- Nearly one quarter (24%) of those surveyed did not think that a moderate decrease in housing or stock market, an increase in interest rates, cuts in salary, or reduced access to credit would noticeably affect their financial situation.

Vulnerable Canadian households

- Certain socio-economic groups are particularly susceptible to increasing debt. The most vulnerable are the hardest hit – low income, households with children, young adults, the retired.
- Canadian families in particular are struggling with increasing debt. Households with one or more children under the age of 18 reported debt as rising more often than those with no children, with 49% reporting their debt had substantially increased.
- Respondents with lower income were much more likely to report increasing debt compared to the respondents in other income groups. And, those with low wealth continue to sink into debt and to experience further deteriorating in their net worth positions.
- Debt-free households do exist of course and 88% of debt-free respondents lived in one or two-person households and were significantly less likely to have children under the age of 18.

Regional differences

- There are regional differences for those carrying household debt.
- As many as 56% of British Columbians told us their debt increased compared to the Canadian average of 42%.
- Some 30% of residents in the Atlantic Provinces maintained an unchanged debt level compared to 23% of the total respondents who said their debt remained the same.
- Debt-free respondents were more likely to be Ontario residents.

Recommendations

Balanced approach

- The current level of indebtedness of Canadian households is a highly disturbing matter, particularly given the extent of the recent economic shocks (income shock, assets price shock and interest rate shock) and prospects for improving household financial security are low.
- Although CGA-Canada recognizes the importance of consumer spending for business development and for economic growth, a balanced approach to spending, saving and paying down debt may be more of a desirable option than trying to promote consumer spending as a solution for the current economic downturn.

- Canadians long-term financial goals should include accumulation of appreciable financial assets, building of a larger more diversified financial cushion and retirement investment.CGA-Canada urges Canadians to consider such savings vehicles as RRSPs and TSFAs.
- CGA-Canada believes debt is rightfully a personal decision, however, it is crucial that Canadians be aware of potential risks of increasing individual household debt.
- It is important to remember that risk tolerances of financial institutions should not be exercised as a substitute for the judgment of individuals who must discern between the good and bad of being in debt.

Financial literacy

- Financial literacy remains an issue – Canadians frequently don't understand the effect of carrying debt and the costs associated with servicing debt.
- Households' knowledge and skill to understand their own financial circumstances and the motivation to borrow, to spend and to save become crucial to marshalling households' financial security and wellbeing.
- Canadians need to take very seriously the issue of developing their financial capability, that is, improving their knowledge, skills and discipline when making financial decisions.
- There is also an opportunity for government and the educational community to help Canadians improve their financial capability.
- More needs to be done in educating the public on money management, spending, shopping habits, warning signs of financial difficulties and obtaining and using credit.

www.muchmormagazine.com/2009/05/the-state-of-canadian-household-debt-in-a-stumbling-economy

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Panel urges co-operation

ECONOMY

Posted By NATHAN TAYLOR, THE PACKET AND TIMES

Posted 6 hours ago

There was a call for a broad, co-operative and environmental approach to getting the community through the recession during a forum last night at the Best Western Mariposa Inn and Conference Centre.

The Ontario Public Service Employees Union (OPSEU) hosted the forum, called Let's Talk Solutions: A Community Response to the Economic Crisis. The intent was to address three key concerns: the impact of the recession, the resources that are in the community, and what's needed from business, government and labour to stimulate the economy.

Despite the fact little more than a dozen people attended, the two-hour discussion was lively.

Linda McDowell, president of the Orillia, Muskoka and District Labour Council, was one of five panellists at the forum. She began by noting the "massive numbers of people" who have lost jobs, referring to the closures of Otaco and Canada Wood and the downsizing of other local businesses.

While this area has food banks, numerous charities, a soup kitchen and other social services, "we need a lot more," McDowell said, adding governments need to re-examine the employment insurance and welfare systems and make them less restrictive.

Coun. Don Evans, executive director of the Sharing Place Food Bank, was another panel-list. He noted the food bank has seen a 30% increase in clients in the past year.

Orillia needs to be viewed as a small community while looking for a solution to the crisis, he said, adding the government must "invest creativity, thought" and substantial funding.

Dan Kerr, manager of events and development with the Downtown Orillia Management Board, highlighted the difficulties faced by downtown businesses. At a time like this, he suggested, people are buying according to price, not quality or service. And, when someone heads across town to pay less for one item at a big-box store, it can lead to even less business in the downtown core in future, he said.

Retail trade is the largest single sector, business-wise, in Orillia : "It's going to hit the downtown as hard, if not harder," than other areas of the city, Kerr said.

Mary O'Farrell-Bowers, dean of community studies with the Orillia campus of Georgian College, said when the economy is poor, the college's enrolment goes up -- "good news for Georgian; bad news for individuals."

Georgian offers the "second career initiative" and is receiving government funding to offer those opportunities to those who have lost jobs during these hard times.

Rounding out the panel was Coun. Joe Fecht, who noted, "for Orillia, there has been a huge impact." Construction, tourism, manufacturing and other job losses have all been felt in the city. He listed some of the income support programs, but said "all of these are totally inadequate to live on for any period of time."

Minimum wage is too low; universal daycare isn't in place; there's not enough affordable housing. He acknowledged the need for public transportation, but added it is "not affordable without significant revenue from the federal government."

All the different voices did relate one common message: Unity -- between residents, businesses, the various sectors and all levels of government -- is essential.

"We need an increased willingness of people to work together," O'Farrell-Bowers said.

Richard Banigan, the former federal Simcoe North NDP candidate, suggested "micro grants" to help people start businesses.

Banigan also was in support of taxes, especially on those who can afford it most.

Simcoe North MP Bruce Stanton said the federal government is "looking at the kind of interventions that are going to get us back on track," including EI reform, infrastructure funding and GST cuts.

He also encouraged businesses to think globally as well as locally.

Mark Hirstwood, a steward with OPSEU Local 330, talked about the economic opportunities of alternative and renewable energy. The installation of wind turbines throughout the Great Lakes could create thousands of jobs, he noted.

Orillia resident Mike McMurter suggested a community forum, just like last night's, was a big part of the solution. He referred to the city's economic development committee -- made up of council representatives and a few "cherry-picked" business owners -- as not being an adequate representation of the city.

The city should consider using forums like last night's more often for its own decision making, McMurter said.

OPSEU will take the feedback and see how it can be put into action in communities.

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Job losses may rise despite recovery

Posted 8 days ago

Despite signs an economic recovery is underway, Finance Minister Jim Flaherty says Canadians should brace themselves for more job losses.

"The employment level will lag the recovery of the economy," said Flaherty. "People should expect that we will have a continuing worsening of the employment numbers over a period of time, and that those numbers won't recover as quickly as the economy recovers."

Flaherty made the comments as Statistics Canada released figures for May, which show the number of people collecting EI benefits is at a 12-year high. There were 778,700 people collecting benefits in May, up 9.2% or 65,600 from April.

Economists say job numbers are a lagging indicator -- unlike the stock market, which is one of the first things to recover after a recession, unemployment can continue to go up for much longer as employers continue to shed jobs.

"That's why the work that we called for in June remains urgently required: To fix the Employment Insurance eligibility system," said Liberal MP Ralph Goodale.

"For everyone who can make a claim for EI benefits, there is another jobless Canadian who cannot. The statistics reveal only half of the problem," he said.

Meanwhile, the Conference Board of Canada released its quarterly survey of business confidence, which suggests Canadian companies are quickly becoming optimistic about the future.

The report says 37.5% of companies said they expected business conditions to improve, while only 15.4% said things would get worse.

The report also says businesses have not been this confident about the future since about six months before the recession began.

THE BARRIE EXAMINER

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Orillia plant closing

ECONOMY

Posted 9 days ago

Parker-Hannifin will shut down its Orillia plant at the end of the year.

Employees learned Friday of the closure of the plant, which makes industrial seals for the automotive, aerospace, and oil and gas markets.

"The closing will begin immediately and will be implemented in different phases and will conclude on Dec. 31, 2009," Sharon Dunlap, corporate communications officer, said yesterday from the company's corporate headquarters in Cleveland, Ohio.

Seventy employees at the Hughes Road facility are affected, she said. The first round of layoffs will happen in October.

The culprit, she said, is a lacking demand for the parts.

"The demand for the division's products has simply declined to levels that can no longer be supported there," Dunlap said.

Friday's announcement was "very much a surprise," said Dale Hogg, staff representative with United Steelworkers' Local 9393.

"A lot of tears were shed," he said.

When the union and company were in negotiations in the spring, Parker-Hannifin was "very adamant that the plant was not closing," Hogg said.

Indeed, the company "had no intention of closing the facility" at that time, Dunlap said.

Since then, however, there has been a "significant decline in our order rates," she said.

Approval to close the facility was given this month, and Parker-Hannifin met with the union and employees "as soon as we practically could" to inform them, she said.

"We're going to do everything we can for our employees," she said, referring to severance packages and assistance with job placement.

The union's goal, Hogg said, is to make sure the employees are "properly handled through the Employment Standards Act."

The union has an action centre that will assist the affected workers with resumes, job applications and the employment insurance process.

"We've lost a lot of employers in Orillia," Hogg said, adding it's frustrating that "there's not a lot we can do."

Dunlap said Parker-Hannifin would also be shutting down its O-ring operation in Lebanon, Tenn., at the end of the month, resulting in the loss of 36 jobs.

BARRIE Advance.com

TeleTech searches for new client

Frank Matys
Employees at TeleTech's Orillia call centre were distraught to learn the company plans to layoff 472 people by the end of July. The company is hoping to find a replacement for its main client, which is pulling out.

An outpouring of grief followed news that TeleTech plans to lay off about 470 staff at its Orillia call centre by the end of July due to the loss of its main client.
“Some people were beside themselves,” recalled employee Brenda Capsticks. “Some people were having anxiety attacks, some people were breaking down crying.”
Other staff approached by Orillia Today declined to speak on the record, but acknowledged the Tuesday announcement had come as a blow.
“It’s an emotional time,” said one during a smoke break.
“A shock,” was how another described the news.
Still others refused to comment, waving away a reporter while heading to their cars.
“I’m not going to answer any questions,” one individual said bluntly. “You’ll have to talk to the site director.”
Mayor Ron Stevens learned of the coming job cuts during a call from the company’s Denver, Co. headquarters on Tuesday morning.
He said that, as of the end of July, the call centre would no longer be fielding calls on behalf of its current client, which “will be leaving and relocated.
“They have also informed us that they have a temporary client in there for awhile to pick up some of the slack, and they are hoping to expand it into a much longer contract,” he said.
TeleTech is in talks with a large company in the hope of securing new work for the Orillia operation, he said.
“Hopefully, they are successful in their negotiations,” Stevens added. “If they are, that client will be moved into that Orillia centre.”
Stevens said he was told 472 people would lose their jobs at the end of July.
“There will be roughly 140 left,” he said.
Capsticks said she was one of a group of employees who in February began answering calls on behalf of the temporary client referred to by Stevens.
“I am very optimistic they will renew their contract for another six months,” she said, noting that the company avoided earlier layoffs by securing the temporary client.
Capsticks is equally hopeful that management will secure more work and avoid the massive layoff currently planned.
“I have every faith that (the site director) will get another client in TeleTech by the 31st of July,” she added.
Site director Trevor Forrester said staff were “very supportive” upon learning of the coming job losses and the effort to recruit a new client.
He said the company is “aggressively” pursuing clients in the hope of retaining jobs at the facility on Hunter Valley Road.
“I am glad that (staff) have a lot of hope, and I have a lot of hope as well,” he said. “I know that the corporate team is looking out for our interests and planning on keeping us open (by attracting another client).”
The company’s sales team would present potential clients, with Forrester helping to determine whether “they fit in with the timeline.
“(Can they start) soon enough?” he said.
A hundred employees are currently working for the temporary client, and company officials say that figure could double by the end of this month.
“Those numbers are fluid,” Forrester said.
Added Stevens:
“They have every intention of trying to keep that centre open. They have a very high opinion of the people who work there. It is just an unfortunate situation that they are hoping to be able to resolve by having another client. They feel very hopeful that they can make this happen.”
Stevens attributed the coming job losses to the economic downturn.
“Like any other corporation, their client is an American-based company, and their economy is in pretty dire straits,” he added.
Stevens said he does not regret council’s decision to give TeleTech a break on leasing costs for the city-owned building that houses the local operation.
“Absolutely not,” he added. “I am not going to say that is the end of TeleTech in Orillia. I am very hopeful they will be able to negotiate this thing.”

APPENDIX 4 – B

A copy of the Orillia Power Employee Performance Plan follows on the next 8 pages.

Orillia Power Corporation

Employee Performance Plan

Manual & Guidelines

January 1, 2008

Table of Contents

Introduction

Orillia Power's Employee Performance Plan (EPP) is a company-wide, results focused program. It has been designed to encourage employees at all levels to strive for the achievement of specific business results and is closely tied to the Vision and Mission of the organization. The plan will focus on a series of critical business results or measures that encourage dedicated and competent performance, while linking the success of the organization to the success of the employees by providing additional monetary compensation when plan targets are achieved or surpassed.

The EPP is a discretionary and variable component of the overall compensation program. As such, the EPP should not be viewed as a guarantee of a monetary provision to either non-union or bargaining unit employees. The plan is not part of the collective agreement and continuation is predicated on business conditions being present to sustain the plan and on approval by the board of directors. In the event of a work stoppage, the plan will be suspended.

Keeping in mind the company's core value of 'Good Communication' employees will be provided with a quarterly update of results with respect to the EPP. This way, employees will be able to keep up to date with the company's performance as the year progresses.

Eligibility

In order to be eligible for an EPP payout in a given year, an employee must meet the following criteria:

- Regular, full-time employee of Orillia Power Corporation or its' subsidiaries.
- Received regular earnings during the plan year.
- The individual is still an employee of the company at the time the EPP is paid out (with the exception of retirees).
- Employee has not been suspended or demoted based on performance or formal discipline during the year.

For employees that retired, were hired, were on maternity / parental or any other form of leave that exceeded one month in duration, their payout will be pro-rated based on the number of months of the year they were active. Only complete months of service would be included in the calculation. For example, if Employee A was hired on March 15th, therefore only active for nine and a half months of the calendar year, their EPP payout for that year would be multiplied by 9/12, as they were active for nine complete months, divided by the 12 months of the year. To further illustrate, if the employee's base payout would have been $1,000, after accounting for the active employment period, the actual payout would be $750 ($1,000 X 9 / 12).

EPP Pool & Performance Measures

The EPP is based on the concept of a pool of funds to be distributed to the employee group. The maximum size of the pool available in any given year is determined by the board of directors during the budgeting process and will be communicated to the employees at the beginning of the year. The pool amount set by the board of directors is the amount that would be paid out if all performance measures are achieved or exceeded for the given year.

The EPP measures, as referred to above, are indicators which track our achievement of key corporate objectives and goals. The measures will be reviewed / set on an annual basis by management and the board of directors. Each year, the details of the measures and the associated weightings will be communicated to staff.

The value of the pool available for distribution to employees would be reduced if we fail to achieve the performance targets for any individual measure. Each measure is treated independently; therefore, failure to achieve the target in one particular measure reduces the pool by the weighting for that measure alone. For example, if the environmental standard was not achieved, there would be a 5% reduction from the pool. To further illustrate, if the initial value of the pool was $60,000 and the environmental standard, weighted at 5%, was not achieved, there would be a $3,000 reduction in the pool ($60,000 X 5%). Therefore, the pool available for distribution to employees would be $57,000.

Refer to Appendix A for details of measures, weighting and calculations.

2008 EPP Measures

As noted above, the measures will be reviewed / set on an annual basis by management and the board of directors. For the 2008 fiscal year the EPP measures will focus on three primary areas:

- Health, Safety & Environment
- Service Quality
- System Reliability and Efficiency

Health, Safety & Environment measures have a total weighting that accounts for 40% of the EPP. Within this category, there are four specific items that are measured and their specific weightings are noted beside each:

- Lost time injuries (20%)
- Consumer and public safety (10%)
- Environmental standards (5%)
- MOL work stoppage orders (5%)

Service Quality measures have a total weighting that accounts for 30% of the EPP. Within this category, there are six specific items that are measured and their specific weightings are noted beside each:

- Emergency response (5%)
- New service connections (5%)
- Underground cable locates (5%)
- Telephone accessibility (5%)
- Appointments kept (5%)
- Written response to inquiries (5%)

System Reliability and Efficiency measures have a total weighting that accounts for 30% of the EPP. Within this category, there are four specific items that are measured and their specific weightings are noted beside each:

- Generation production efficiency - Lost Production Indicator (15%)
- SAIDI - average outage duration (5%)
- SAIFI - outage instances (5%)
- CAIDI - speed of response (5%)

The standard or target performance level for each of the above noted individual measures is shown in ‘Appendix A’.

Individual Payout Calculations

Once any deductions for measures that were not achieved have been calculated, the residual value of the pool of EPP funds will be used to calculate individual payouts. The payout for each eligible employee is based on a pro-rata calculation using individual basic compensation of each employee over the total basic compensation of all eligible employees. For example, if Employee A has basic compensation of $56,000 per year and the total basic compensation of all eligible employees is $2,800,000 then Employee A would be eligible for 2.0% of the pool ($56,000 / $2,800,000 X100). Assuming the pool in that given year was $60,000 Employee A would be eligible for an EPP of $1,200 ($60,000 X 2%).

An employee's basic compensation is defined as their hourly rate (as of December 31st for the year being measured) times their regular scheduled hours in a week times 52 weeks. Therefore, if Employee A earns $28.55 per hour and has a regular work week of 40 hours, their basic compensation would be $59,384 ($28.55 X 40 hours X 52 weeks).

Once the individual payout is calculated, based on the achievement of measures and the pro-rata portion of individual compensation, an attendance factor will be applied to the individual payout. The attendance factor works as follows:

- An employee with three (3) or less sick leave absence occurrences in the calendar year, will receive their full individual EPP payout
- If an employee has four (4) sick leave absence occurrences during the year, their individual EPP payout will be reduced by 1/6th
- Each subsequent sick leave absence occurrence will reduce the individual payout by an additional 1/6th

A sick leave absence occurrence is defined as a period of work missed due to sickness that begins from the first day of work missed and continues until the employee returns to work. For example, if an employee calls in sick on Wednesday morning and returns to work Thursday, they are absent for one day and that is considered one sick leave absence occurrence. If the employee did not return to work until the Friday, they would have missed two days of work, but it would only be considered one sick leave absence occurrence. If however, the employee was off sick on Wednesday, returned to work on Thursday, but called in sick again on Friday, that would be considered two sick leave absence occurrences.

To illustrate the impact of the attendance factor, assume that Employee A is eligible for an individual EPP of $1,200 prior to applying the attendance factor. If Employee A had five sick leave absence occurrences during the year, their individual payout would be reduced by 2/6ths or $400 ($1,200 X 2/6). If Employee A had incurred three or less sick leave absence occurrences during the year, there would have been no reduction in their individual payout and they would have received $1,200.

The following table illustrates the impact on individual EPP payouts based on various attendance scenarios:

# of sick leave absence occurrences in year	Reduction to Individual EPP
3 or less	no reduction
4	1/6
5	2/6
6	3/6
7	4/6
8	5/6
9 or more	6/6 (no individual payout)

The annual payment of EPP is subject to final approval by the board of directors, with a payment date scheduled by the end of February. For example, the payout based on the 2008 measures and performance will occur in February 2009. Employees should note that EPP payouts will be subject to income taxes per Canada Revenue Agency rules in addition to other statutory deductions.

Dispute Resolution Process

In the event that an employee has a dispute with the calculation of their individual EPP payout, they must submit their reason for disputing, in writing, to the Human Resources Officer. Any disputes must be filed within two weeks of the scheduled payout date. The situation will be reviewed by the Human Resources Officer, the Treasurer and the President and a final, binding decision with respect to the disputed EPP will be returned to the employee within two weeks from the date that the written dispute document is received.

Questions or Interpretations

An employee who has any questions or requires clarification or interpretation of any of the foregoing information is advised to direct such inquiries to the Human Resources Officer.

Appendix A
Sample Calculation

Employee Performance Plan Available for Payout BEFORE Deductions						$60,000
Objectives and Measures Based on Mission and Vision		**Objectives and Measures Weighting**	**Standard Required**	**Results Achieved**	**Category Eligible for Incentive?**	**Deductions from EPP Available**
Health, Safety and Environment Measures						
Lost Time Injuries	No lost time injuries for year	20.0%	0	0	**YES**	**0**
Public Safety	No reportable injuries to the public caused by OPC	10.0%	0	0	**YES**	**0**
Environmental Standards	No warnings or charges from MOE documented	5.0%	0	0	**YES**	**0**
Work stoppage orders	No MOL charges or work stoppage orders documented	5.0%	0	0	**YES**	**0**
		40.0%				
Service Quality Indicators						
Emergency response	Respond within 60 minutes (OEB requires 80%)	5.0%	90.0%	100.0%	**YES**	**0**
Connection of New Services	Within 5 Working Days (OEB requires 90%)	5.0%	95.0%	100.0%	**YES**	**0**
Underground cable locates	Within 5 Working Days (OEB requires 90%)	5.0%	95.0%	100.0%	**YES**	**0**
Telephone accessibility	Answer within 30 Seconds (OEB requires 65%)	5.0%	85.0%	96.0%	**YES**	**0**
Appointments kept	Meet at appointed time (OEB requires 90%)	5.0%	95.0%	100.0%	**YES**	**0**
Written response to inquiries	Respond within 10 days (OEB requires 80%)	5.0%	90.0%	92.0%	**YES**	**0**
		30.0%				
Reliability Indicators	*(SAIDI, SAIFI & CAIDI exclude H1 impact)*					
Lost Production Indicator	Target established annually	15.0%	0.980	0.992	**YES**	**0**
SAIDI (avg outage duration)	2006 Average for medium sized LDCs 1.59	5.0%	1.250	0.810	**YES**	**0**
SAIFI (outage instances)	2006 Average for medium sized LDCs 1.25	5.0%	1.000	0.680	**YES**	**0**
CAIDI (speed of response)	Target calculated as SAIDI / SAIFI	5.0%	1.250	1.191	**YES**	**0**
		30.0%				
		100.0%				
Employee Performance Plan Payout for Year						**$60,000**

APPENDIX 4 – C

A copy of OPDC's Shared Services Methodology and prices paid for services from 2006 Actual through to 2010 Test follows on the next 7 pages.

SHARED SERVICES METHODOLOGY

Type of Service	Cost Allocator	Cost Allocation %	
Year 2006		Distribution	Generation
Management services	% of time spent	63%	37%
General admin services	% of time spent	63%	37%
General financial services	% of time spent	63%	37%
Purchasing services	% of time spent	63%	37%
Phone/Fax and office supplies	% of time spent	63%	37%
IT Support	% of time spent	63%	37%
Accounting Software Maint/Hosting	% of time spent	63%	37%
Service Centre rent	Square footage	85%	15%
SCADA monitoring services	% of time spent	50%	50%
SCADA monitoring services - premium	Direct charge	na	na
Supplies and maintenance	% of time spent	50%	50%

Type of Service	Cost Allocator	Cost Allocation %	
Year 2007		Distribution	Generation
Management services	% of time spent	67%	33%
General admin services	% of time spent	67%	33%
General financial services	% of time spent	67%	33%
Purchasing services	% of time spent	67%	33%
Phone/Fax and office supplies	% of time spent	67%	33%
IT Support	% of time spent	67%	33%
Accounting Software Maint/Hosting	% of time spent	67%	33%
Service Centre rent	Square footage	85%	15%
SCADA monitoring services	% of time spent	50%	50%
SCADA monitoring services - premium	Direct charge	na	na
Supplies and maintenance	% of time spent	50%	50%

Type of Service	Cost Allocator	Cost Allocation %	
Year 2008		Distribution	Generation
Management services	% of time spent	67%	33%
General admin services	% of time spent	67%	33%
General financial services	% of time spent	67%	33%
Purchasing services	% of time spent	67%	33%
Phone/Fax and office supplies	% of time spent	67%	33%
IT Support	% of time spent	67%	33%
Accounting Software Maint/Hosting	% of time spent	67%	33%
Service Centre rent	Square footage	85%	15%
SCADA monitoring services	% of time spent	50%	50%
SCADA monitoring services - premium	Direct charge	na	na
Supplies and maintenance	% of time spent	50%	50%

SHARED SERVICES METHODOLOGY

Type of Service	Cost Allocator	Cost Allocation %	
Year 2009 Bridge		Distribution	Generation
Management services	% of time spent	67%	33%
General admin services	% of time spent	67%	33%
General financial services	% of time spent	67%	33%
Purchasing services	% of time spent	67%	33%
Phone/Fax and office supplies	% of time spent	67%	33%
IT Support	% of time spent	67%	33%
Accounting Software Maint/Hosting	% of time spent	67%	33%
Service Centre rent	Square footage	85%	15%
SCADA monitoring services	% of time spent	50%	50%
SCADA monitoring services - premium	Direct charge	na	na
Supplies and maintenance	% of time spent	50%	50%

Type of Service	Cost Allocator	Cost Allocation %	
Year 2010 Test		Distribution	Generation
Management services	% of time spent	67%	33%
General admin services	% of time spent	67%	33%
General financial services	% of time spent	67%	33%
Purchasing services	% of time spent	67%	33%
Phone/Fax and office supplies	% of time spent	67%	33%
IT Support	% of time spent	67%	33%
Accounting Software Maint/Hosting	% of time spent	67%	33%
Service Centre rent	Square footage	85%	15%
SCADA monitoring services	% of time spent	50%	50%
SCADA monitoring services - premium	Direct charge	na	na
Supplies and maintenance	% of time spent	50%	50%

Shared Services
For the Year 2006

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($1,000's)	Cost for the Service ($1,000's)	% Allocation
From	To					
Orillia Power Distribution	Orillia Power Generation	Management services	Fully allocated cost plus rate of return	151		37%
		General admin services	Fully allocated cost plus rate of return	52		37%
		General financial services	Fully allocated cost plus rate of return	46		37%
		Purchasing services	Fully allocated cost plus rate of return	15		37%
		Phone/Fax and office supplies	Fully allocated cost plus rate of return	41		37%
		Reconstruction of OPC website	Fully allocated cost plus rate of return	3		37%
		Vision & Mission Workshops	Fully allocated cost plus rate of return	5		37%
		IT Support	Fully allocated cost plus rate of return	10		37%
		Accounting Software Maint	Fully allocated cost plus rate of return	9		37%
Orillia Power Distribution	Orillia Power Generation	Service Centre rent	Fully allocated cost plus rate of return	34		15%
Orillia Power Distribution	Orillia Power Generation	SCADA monitoring services	Fully allocated cost plus rate of return	161		50%
		Supplies and maintenance	Fully allocated cost plus rate of return	52		50%
Orillia Power Generation	Orillia Power Distribution	SCADA supervisory services	Fully allocated cost		63	N/A
		SCADA supplies and maintenance	Fully allocated cost		64	N/A
Orillia Power Distribution	Orillia Power Generation	SCADA relief operator services	Fully allocated cost plus rate of return	14		N/A
		Generating station services & supplies	Fully allocated cost plus rate of return	89		N/A
		SCADA monitoring services - premium	Fully allocated cost plus rate of return	65		N/A
		Engineering services	Fully allocated cost plus rate of return	62		N/A
		Make Ready Services - SCBN Telecom	Fully allocated cost plus rate of return	51		N/A
Orillia Power Generation	Orillia Power Distribution	Substation maintenance services	Fully allocated cost plus rate of return		74	N/A
		Project management services	Fully allocated cost plus rate of return		21	N/A
		Construction services - Jarvis St Substation	Fully allocated cost plus rate of return		74	N/A
Orillia Power Generation	Orillia Power Distribution	Service Centre maintenance	Fully allocated cost		29	N/A
Orillia Power Generation	Orillia Power Distribution	Sale of Power - embedded generation	Spot market pricing		921	N/A
Orillia Power Distribution	Orillia Power Corporation	Directors out of pocket expenses	Fully allocated cost	9		N/A
Orillia Power Distribution	City of Orillia	Streetlight maintenance	Market-based pricing	36		N/A
		Capital projects - City driven	Market-based pricing	69		N/A
		Electricity	Market-based pricing	1,291		N/A
City of Orillia	Orillia Power Distribution	Property taxes	Market-based pricing		64	N/A
		Fuel for vehicles	Market-based pricing		47	N/A
		Miscellaneous services	Market-based pricing		18	N/A
		Traffic light conversion (CDM 3rd Tranche Spending)	Market-based pricing		10	N/A
		Interest of promissory note	Agreement		610	N/A
Orillia Power Distribution	SCBN Telecommunications	Pole access charges	Market-based pricing	17		N/A
SCBN Telecommunications	Orillia Power Distribution	Internet services	Market-based pricing		29	N/A
		Fibre optic connection - new substation	Market-based pricing		2	N/A

Shared Services **For the Year 2007**						
Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service ($1,000's)**	**Cost for the Service ($1,000's)**	**% Allocation**
From	**To**					
Orillia Power Distribution	Orillia Power Generation	Management services	Fully allocated cost plus rate of return	142		33%
		General admin services	Fully allocated cost plus rate of return	53		33%
		General financial services	Fully allocated cost plus rate of return	47		33%
		Purchasing services	Fully allocated cost plus rate of return	17		33%
		Phone/Fax and office supplies	Fully allocated cost plus rate of return	39		33%
		IT Support	Fully allocated cost plus rate of return	12		33%
		Accounting Software Maint	Fully allocated cost plus rate of return	8		33%
Orillia Power Distribution	Orillia Power Generation	Service Centre rent	Fully allocated cost plus rate of return	36		15%
Orillia Power Distribution	Orillia Power Generation	SCADA monitoring services	Fully allocated cost plus rate of return	194		50%
		Supplies and maintenance	Fully allocated cost plus rate of return	48		50%
Orillia Power Generation	Orillia Power Distribution	SCADA supervisory services	Fully allocated cost		70	N/A
		SCADA supplies and maintenance	Fully allocated cost		81	N/A
Orillia Power Distribution	Orillia Power Generation	SCADA relief operator services	Fully allocated cost plus rate of return	13		N/A
		Generating station services & supplies	Fully allocated cost plus rate of return	78		N/A
		SCADA monitoring services - premium	Fully allocated cost plus rate of return	69		N/A
		Engineering services	Fully allocated cost plus rate of return	62		N/A
Orillia Power Generation	Orillia Power Distribution	Substation maintenance services	Fully allocated cost plus rate of return		59	N/A
		Project management services	Fully allocated cost plus rate of return		20	N/A
Orillia Power Generation	Orillia Power Distribution	Service Centre maintenance	Fully allocated cost		18	N/A
Orillia Power Generation	Orillia Power Distribution	Sale of Power - embedded generation	Spot market pricing		758	N/A
Orillia Power Distribution	Orillia Power Corporation	Directors out of pocket expenses	Fully allocated cost	9		N/A
Orillia Power Distribution	City of Orillia	Streetlight maintenance	Market-based pricing	35		N/A
		Capital projects - City driven	Market-based pricing	44		N/A
		Electricity	Market-based pricing	1,277		
City of Orillia	Orillia Power Distribution	Property taxes	Market-based pricing		64	N/A
		Fuel for vehicles	Market-based pricing		52	N/A
		Miscellaneous services	Market-based pricing		21	N/A
		Answering service	Market-based pricing		18	N/A
		Traffic light conversion (CDM 3rd Tranche Spending)	Market-based pricing		7	N/A
		Interest of promissory note	Agreement		610	N/A
SCBN Telecommunications	Orillia Power Distribution	Internet services	Market-based pricing		8	N/A

Shared Services **For the Year 2008**						
Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service ($1,000's)**	**Cost for the Service ($1,000's)**	**% Allocation**
From	**To**					
Orillia Power Distribution	Orillia Power Generation	Management services	Fully allocated cost	147		33%
		General admin services	Fully allocated cost	56		33%
		General financial services	Fully allocated cost	48		33%
		Purchasing services	Fully allocated cost	17		33%
		Phone/Fax and office supplies	Fully allocated cost	34		33%
		IT Support	Fully allocated cost	12		33%
		Accounting Software Maint/Hosting	Fully allocated cost	10		33%
Orillia Power Distribution	Orillia Power Generation	Service Centre rent	Fully allocated cost	37		15%
Orillia Power Distribution	Orillia Power Generation	SCADA monitoring services	Fully allocated cost	174		50%
		Supplies and maintenance	Fully allocated cost	57		50%
Orillia Power Generation	Orillia Power Distribution	SCADA supervisory services	Fully allocated cost		64	N/A
		SCADA supplies and maintenance	Fully allocated cost		76	N/A
Orillia Power Distribution	Orillia Power Generation	SCADA relief operator services	Fully allocated cost plus rate of return	13		N/A
		Generating station services & supplies	Fully allocated cost plus rate of return	84		N/A
		SCADA monitoring services - premium	Fully allocated cost plus rate of return	60		N/A
		Engineering services	Fully allocated cost plus rate of return	96		N/A
Orillia Power Generation	Orillia Power Distribution	Substation maintenance services	Fully allocated cost plus rate of return		110	N/A
		Project management services	Fully allocated cost plus rate of return		29	N/A
Orillia Power Generation	Orillia Power Distribution	Service Centre maintenance	Fully allocated cost		29	N/A
Orillia Power Generation	Orillia Power Distribution	Sale of Power - embedded generation	Spot market pricing		1,052	N/A
Orillia Power Distribution	Orillia Power Corporation	Directors out of pocket expenses	Fully allocated cost	8		N/A
Orillia Power Distribution	City of Orillia	Streetlight maintenance	Market-based pricing	41		N/A
		Capital projects - City driven	Market-based pricing	73		N/A
		Electricity	Market-based pricing	1,214		
City of Orillia	Orillia Power Distribution	Property taxes	Market-based pricing		70	N/A
		Fuel for vehicles	Market-based pricing		63	N/A
		Miscellaneous services	Market-based pricing		35	N/A
		Answering service	Market-based pricing		18	N/A
		Street light LED pilot project (Community Initiatives Fund)	Market-based pricing		10	N/A
		Interest of promissory note	Agreement		610	N/A

Shared Services **For the 2009 Bridge Year**						
Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service ($1,000's)**	**Cost for the Service ($1,000's)**	**% Allocation**
From	**To**					
Orillia Power Distribution	Orillia Power Generation	Management services	Fully allocated cost	138		33%
		General admin services	Fully allocated cost	53		33%
		General financial services	Fully allocated cost	45		33%
		Purchasing services	Fully allocated cost	16		33%
		Phone/Fax and office supplies	Fully allocated cost	40		33%
		IT Support	Fully allocated cost	13		33%
		Accounting Software Maint/Hosting	Fully allocated cost	12		33%
Orillia Power Distribution	Orillia Power Generation	Service Centre rent	Fully allocated cost	36		15%
Orillia Power Distribution	Orillia Power Generation	SCADA monitoring services	Fully allocated cost	188		50%
		Supplies and maintenance	Fully allocated cost	61		50%
Orillia Power Generation	Orillia Power Distribution	SCADA supervisory services	Fully allocated cost		70	N/A
		SCADA supplies and maintenance	Fully allocated cost		81	N/A
Orillia Power Distribution	Orillia Power Generation	SCADA relief operator services	Fully allocated cost plus rate of return	13		N/A
		Generating station services & supplies	Fully allocated cost plus rate of return	85		N/A
		SCADA monitoring services - premium	Fully allocated cost plus rate of return	60		N/A
		Engineering services	Fully allocated cost plus rate of return	101		N/A
Orillia Power Generation	Orillia Power Distribution	Substation maintenance services	Fully allocated cost plus rate of return		115	N/A
		Project management services	Fully allocated cost plus rate of return		26	N/A
Orillia Power Generation	Orillia Power Distribution	Service Centre maintenance	Fully allocated cost		29	N/A
Orillia Power Generation	Orillia Power Distribution	Sale of Power - embedded generation	Spot market pricing		600	N/A
Orillia Power Distribution	Orillia Power Corporation	Directors out of pocket expenses	Fully allocated cost	8		N/A
Orillia Power Distribution	City of Orillia	Streetlight maintenance	Market-based pricing	42		N/A
		Capital projects - City driven	Market-based pricing	75		N/A
		Electricity	Market-based pricing	1,200		
City of Orillia	Orillia Power Distribution	Property taxes	Market-based pricing		70	N/A
		Fuel for vehicles	Market-based pricing		65	N/A
		Miscellaneous services	Market-based pricing		35	N/A
		Answering service	Market-based pricing		18	N/A
		Interest of promissory note	Agreement		610	N/A

Shared Services **For the 2010 Test Year**						
Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service ($1,000's)**	**Cost for the Service ($1,000's)**	**% Allocation**
From	**To**					
Orillia Power Distribution	Orillia Power Generation	Management services	Fully allocated cost	144		33%
		General admin services	Fully allocated cost	55		33%
		General financial services	Fully allocated cost	47		33%
		Purchasing services	Fully allocated cost	16		33%
		Phone/Fax and office supplies	Fully allocated cost	41		33%
		IT Support	Fully allocated cost	13		33%
		Accounting Software Maint/Hosting	Fully allocated cost	15		33%
Orillia Power Distribution	Orillia Power Generation	Service Centre rent	Fully allocated cost	37		15%
Orillia Power Distribution	Orillia Power Generation	SCADA monitoring services	Fully allocated cost	200		50%
		Supplies and maintenance	Fully allocated cost	61		50%
Orillia Power Generation	Orillia Power Distribution	SCADA supervisory services	Fully allocated cost		73	N/A
		SCADA supplies and maintenance	Fully allocated cost		81	N/A
Orillia Power Distribution	Orillia Power Generation	SCADA relief operator services	Fully allocated cost plus rate of return	14		N/A
		Generating station services & supplies	Fully allocated cost plus rate of return	87		N/A
		SCADA monitoring services - premium	Fully allocated cost plus rate of return	62		N/A
		Engineering services	Fully allocated cost plus rate of return	105		N/A
Orillia Power Generation	Orillia Power Distribution	Substation maintenance services	Fully allocated cost plus rate of return		117	N/A
		Project management services	Fully allocated cost plus rate of return		26	N/A
Orillia Power Generation	Orillia Power Distribution	Service Centre maintenance	Fully allocated cost		30	N/A
Orillia Power Distribution	Orillia Power Corporation	Directors out of pocket expenses	Fully allocated cost	8		N/A
Orillia Power Distribution	City of Orillia	Streetlight maintenance	Market-based pricing	43		N/A
		Capital projects - City driven	Market-based pricing	75		N/A
		Electricity	Market-based pricing	1,200		
City of Orillia	Orillia Power Distribution	Property taxes	Market-based pricing		70	N/A
		Fuel for vehicles	Market-based pricing		67	N/A
		Miscellaneous services	Market-based pricing		35	N/A
		Answering service	Market-based pricing		18	N/A
		Interest of promissory note	Agreement		610	N/A

APPENDIX 4 – D

A copy of OPDC's Expenditure Controls Policy follows on the next 7 pages.

ORILLIAPOWER
Energizing Our Community

OPC POLICY & PROCEDURE MANUAL

Title: Expenditure Controls	Number: 05 - 06
Subject: Accounting & Finance Policy	Date: November 24, 2005
Revised: September 18, 2007	Page 1

POLICY

The initiation, approval and payment of all expenditures / purchase of goods and or services required in the normal course of business shall be done within proper authorization limits and subject to appropriate internal controls and guidelines as documented in this policy.

PURPOSE

To establish guidelines and controls for the purchase of all goods and services required by the Corporation and its subsidiaries. These guidelines establish authorization levels for expenditures of company funds.

OBJECTIVES

Employees acting within proper authority shall purchase the appropriate goods and services, in the appropriate quantity, at the appropriate time, at the appropriate price and to have the goods and services delivered as required.

CODE OF CONDUCT, SAFETY AND THE ENVIRONMENT

Employees shall always perform their duties in a manner that honours Orillia Power Corporation's code of conduct. In particular, employees shall conduct business honestly, lawfully and ethically.

OPC recognizes the importance of preserving the environment, conserving natural resources and protecting human health. It is imperative that all purchasing decisions keep these objectives at the forefront. All purchases are to meet or exceed applicable safety standards as governed by the regulatory bodies applicable to OPC.

DEFINITIONS

"Department Head" means the Treasurer, the Distribution Superintendent or the Generation Superintendent.

"Supervisor" means someone not defined as a Department Head directly reporting to a Department Head or the President.

"Designate" means a person fulfilling the duties of a Supervisor, Department Head or the President while they are away from the office. Unless otherwise stated, references to a Supervisor, Department Head or President shall include the Designate.

Note to policy: All references to dollar figures are before applicable taxes.

Title: Expenditure Controls	Number: 05 - 06
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STAFF AUTHORITY TO INITIATE EXPENDITURE COMMITMENTS
Authority of staff to initiate purchase commitments for business purposes is as follows:

Goods and Services Purchase Commitments Up To $150,000:

- Expenditure commitments less than $250: may be initiated by operating staff provided that verbal Supervisor approval has been received prior to making the purchase commitment.
- Expenditure commitments from $250 and less than $1,500: shall be authorized by the appropriate Supervisor.
- Expenditure commitments from $1,500 and above: shall be authorized by the appropriate Department Head.
- Expenditure commitments from $3,000 and less than $15,000: shall be authorized by the President.
- Discretionary expenditure commitments from $15,000 and up to $150,000: shall always be authorized by the President. Other than for inventory purchases, supporting written documentation justifying the expenditure shall be provided by a Department Head to facilitate this approval. While a Designate may initially authorize the expenditure in emergency situations, authorization shall be obtained after the fact from the President at the first opportunity.
- Non-discretionary expenditure commitments from $3,000 and above: shall be authorized by the Treasurer. Presidential approval for items including but not necessarily limited to income and other taxes, payroll and payroll withholdings would normally always be given. By nature these types of expenditures are subject to additional controls or government regulation.

EXPENDITURE COMMITMENTS REQUIRING BOARD APPROVAL

Annual Capital, Operating and Financial Budgets
The Board of Directors shall review and approve the annual capital, operating and financial budgets of the Corporation and it's subsidiaries. For major purchases not incorporated into the fiscal budget, the Board of Directors normally delegates authorization responsibility to the President subject to the limits set out below.

Goods and Services Purchase Commitments From $150,000 and Above:

- Expenditures where the total purchase commitment is from $150,000 and above shall be authorized by the President and the Chairman of the Board of Directors (or the Vice Chairman when Chairman unavailable). Evidence of this authorization shall be on the purchase order if applicable.
- Individual Capital expenditures for grouped assets (example overhead distribution lines) that are less than $150,000 but as a related group combine to total more than $150,000 would normally be reviewed and approved by the Board as part of the annual budget process. The individual transactions would be reviewed and approved using the normal guidelines outlined above.

Significant contracts or agreements
Board of Director approval shall be sought by the President to enter into any agreement or contract that may materially affect the direction or the finances of the corporation. This includes but is not necessarily restricted to:

- Acquisitions, or the purchase of a business
- Divestitures or the sale of part of the business
- Any contract outside the ordinary course of business
- Any two-year contract committing to annual expenditures of greater than or equal to $80,000 per year.
- Any three-year contract committing to annual expenditures of greater than or equal to $60,000 per year.
- Any contract extending beyond three years other than operating leases.

PURCHASING / STORES PERSON RESPONSIBILITIES

As part of purchasing responsibilities, as a minimum, the Purchasing Stores Person is accountable for:

- Establishing supplier contracts (if applicable)
- Managing the competitive bidding process
- Selecting suppliers in conjunction with other OPC staff.
- Maintaining supplier records
- Managing the Purchase Order system
- Ensuring that all purchases are appropriately authorized
- Minimizing inventory levels while not compromising operating capability

SOURCING LIMITS FOR GOODS AND SERVICES

Materials which are regularly used by the Corporation shall, where practical, be held in stock and managed as part of the computerized inventory system and be replenished at levels appropriate to usage and price breaks. Occasional use goods and services shall be sourced under the direction of the Department Head. Some purchases may not be readily available from multiple approved suppliers, and as such, necessitate variations in the procedure set out below.

Delivery, quality, service, as well as price shall be considered in determining the selection of supplier. F.O.B. points and discounts shall also be considered when evaluating price. The following dollar value limits apply when obtaining product or service pricing provided that multiple approved vendors are available:

- Purchases less than $1,500: Depending on the nature of the item and at the discretion of the Purchasing Stores Person, one to three verbal quotations shall be obtained. Pricing should be checked at regular intervals for repeat purchases under $1,500.

- Purchases from $1,500 and above: Three written quotations shall be obtained before issuing the purchase order.

- Purchases from $40,000 and above: Purchases with an expected value from $40,000 and above shall be tendered, advertised or invited, as appropriate for the particular material or service being purchased. Tender openings shall be coordinated through the Purchasing Stores Person and shall be attended by the Treasurer and the Department Head.

PURCHASE ORDERS

The purchase order is the legal document authorizing a supplier to provide goods and services and invoice the Corporation accordingly. The Purchasing Stores Person shall ensure that appropriate authorization has been obtained prior to issuing a commitment to purchase goods and services. Purchases of goods and services from $500 and above shall be supported by an approved purchase order, except in the case of regular predictable expenses such as rent or utilities, which are subject to other forms of review.

Purchases large enough to require a purchase order would normally be initiated by any operating department by completing a properly authorized purchase requisition form and submitting it to the Purchasing Stores Person for processing.

Before a purchase order can be issued it shall be signed by someone with appropriate authority to do so as outlined above under the section "Staff Authority to Initiate Expenditure Commitments". Purchases large enough to require a purchase order would normally only be made by the company's Purchasing Stores Person and not by operating staff.

In the event that actual costs will exceed the value of an authorized purchase order and the purchase order initiator is satisfied that the incremental costs are legitimate and reasonable, the purchasing stores person shall revise the value of the original purchase order. The revised purchase order must be attached to the authorized original purchase order. In the description section of the revised purchase order, a clear explanation of the change / reason for the change must be provided.

The revised purchase order must be authorized based on the amount that it exceeds the original purchase order value in accordance with the thresholds noted in the section titled 'Staff Authority to Initiate Expenditure Commitments' on page 2 of this document. For example, if the revision represents an increase between $1,500 and $3,000 over the original purchase order, the Department Head would be required to authorize the change.

CONFIRMATION OF RECEIPT OF PURCHASED GOODS AND SERVICES

Prior to payment approval, appropriate documentation shall be provided confirming the receipt of the purchased goods and services **in satisfactory condition and good working order** by the transaction originator. If the transaction originator does not directly oversee the use of the goods and or services, then the appropriate individual shall also sign.

Title: Expenditure Controls	Number: 05 - 06
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PAYMENTS FOR PURCHASED GOODS AND SERVICES

Invoice vouchers summarizing expenditures shall have complete supporting documentation as applicable in order for payment to be authorized. Supporting documentation would normally include but not necessarily be limited to requisitions, purchase orders, receiving slips and supplier invoices. Supporting documentation shall also include (1) evidence that proper expenditure control authorization limits have been followed and (2) sign-off by the transaction originator that goods and or services were received as expected.

Subject to evidence that complete supporting documentation exists as outlined above, authorization to pay an invoice shall be given as follows:

- Invoices less than $250: shall be authorized by operating staff or Supervisor.
- Invoices from $250 and less than $1,500: shall be authorized by the appropriate Supervisor.
- Invoices from $1,500 and above: shall be authorized by the appropriate Department Head.
- Invoices from $3,000 and above: shall be authorized by the President unless item is a statutory, non-discretionary expenditure as outlined above in which case it shall be authorized by the Treasurer.

Accounting shall obtain final signoff approval by the Treasurer for payments from $1,500 and above or if amount less than $1,500, the Accountant prior to payment of invoice.

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EXCEPTIONS TO NORMAL AUTHORIZATION PROCESSES

Use of Business Visa Cards
For expediency, smaller purchases for business related expenditures may be made using Visa purchasing cards issued to authorized personnel. Unless Presidential approval is sought ahead of making the expenditure, the spending limit on a single business related visa purchase for Supervisors and Department Heads is $1,500. Unless Supervisor approval is acquired ahead of making the expenditure, the spending limit on a single business related visa purchase for non-supervisory staff is $500.

Approvals to exceed the normal limits shall be documented in writing (email confirmation is sufficient). No purchase order would normally be required.

Adherence to the Corporation's credit card policy is required at all times.

Petty Cash
Certain expenditures would not normally go through the invoice voucher authorization process as follows. Business expenditures up to $100 may be initiated by staff and paid for out of the office Petty Cash fund provided there has been Supervisor approval given at the time of the expenditure. Other than for petty cash expenditures, paying "Cash on Delivery" would not normally be permitted.

EMERGENCY PURCHASES

This policy shall not be interpreted as prohibiting emergency purchases; however, such purchases shall be followed up for approval, in accordance with this policy.

Signature of Department Head: ____________

Signature of President: ____________

APPENDIX 4 – E

A copy of the 2006 EDR Handbook Appendix B: Amortization Rates follows on the next 2 pages.

Appendix B

Appendix B: Amortization Rates

The amortization rates below apply to the respective assets listed under "Asset Type". All rates are based on the straight line method of amortization.

The inclusion of an asset in the chart below does not imply Board acceptance of the asset for inclusion in the Rate Base or for any other rate making purpose.

The amortization expense related to an asset used for both Distribution and Non-utility activities should be properly allocated to each type of activity. Only the amortization expenses related to distribution assets may be included as an expense in rate applications. The method of allocation should be reasonable and documented.

		Effective January 1, 1992		Prior to January 1, 1992	
USoA Account	**Asset Type**	**Life-Years**	**Rate**	**Life-Years**	**Rates**
1930 1950	Rolling Stock and Equipment[1] Automobiles Trucks under 3 tonnes Trucks 3 tonnes and over Work and service equipment	4 5 8 8	25.00% 20.00% 12.50% 12.50%	4 5 8 8	25.00% 20.00% 12.50% 12.50%
Part of 1620, 1708, 1808, 1908 (as applicable)	Buildings and fixtures: brick, stone, concrete, and steel	50	2.00%	60	1.67%
1920	Computer equipment: hardware	5	20.00%	5	20.00%
1830, 1835, part of 1855	Distribution lines and feeders: overhead	25	4.00%	25	4.00%
1840, 1845, part of 1855	Distribution lines and feeders: underground	25	4.00%	25	4.00%
1860	Distribution meters	25	4.00%	25	4.00%
1850	Distribution transformers	25	4.00%	25	4.00%
1915	General office equipment	10	10.00%	10	10.00%
1635 to 1685	Generating stations	60	1.67%	60	1.67%

[1] No allowance will be made for residual value.

		Effective January 1, 1992		Prior to January 1, 1992	
USoA Account	**Asset Type**	**Life-Years**	**Rate**	**Life-Years**	**Rates**
1615, 1705, 1805, 1905	Land	Non-depreciable		Non-depreciable	
1630, 1710, 1810, 1910	Leasehold improvements	Over term of lease		Over term of lease	
1970	Load management controls: customer premises	10	10.00%	15	6.67%
1975	Load management controls: utility premises	10	10.00%	15	6.67%
1940	Miscellaneous equipment, major tools, and instruments	10	10.00%	10	10.00%
1820	Municipal distribution station equipment (below 50 kV)	30	3.33%	30	3.33%
1815, 1715	Municipal transformer stations equipment (above 50 kV)	40	2.50%	40	2.50%
1985	Sentinel lighting rental units	10	10.00%	10	10.00%
1935	Stores warehouse equipment	10	10.00%	10	10.00%
Below 50 kV relates to part of 1720, 1725, and 1735 Above 50 kV relates to 1830 and 1835	Sub-transmission feeders: overhead	25	4.00%	25	4.00%
Below 50 kV relates to 1840 and 1845 Above 50 kV relates to 1735 and 1740	Sub-transmission feeders: underground	25	4.00%	25	4.00%
1980	System supervisory equipment	15	6.67%	25	4.00%
Part of 1725 and 1730	Transmission lines: wood poles	25	4.00%	25	4.00%
1965	Water heater rental units	10[2]	10.00%	10[2]	10.00

[2] In areas where water conditions are deemed to affect the life of water heaters, a different depreciation rate may be approved. Applicants will be required to file full details as to the determination of such a rate.

APPENDIX 4 – F

A copy of OPDC's 2008 Tax Return (T2 and CT23) follows on the next 62 pages.

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

PLEASE RETAIN THIS COPY FOR YOUR FILES

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 86512 0596 RC0001

Corporation's name

002 Orillia Power Distribution Corporation

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes [ ] 2 No [X]

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 [X]
(If **yes**, complete lines 011 to 018)

011 360 West St S
012 P.O. Box 398
City: 015 Orillia
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 L3V 6J9

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028)

021 c/o
022 P.O. 398
023
City: 025 Orillia
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 L3V 6J9

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038)

031 360 West St S
032 P.O. Box 398
City: 035 Orillia
Province,territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 L3V 6J9

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ________ YYYY MM DD

To which tax year does this return apply?

Tax year start 060 2008-01-01 (YYYY MM DD)
Tax year-end 061 2008-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired 065 ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X
What is the corporation's major business activity? (Only complete if **yes** was entered at line 281)	282		
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283	1 Wholesale	2 Retail

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any 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		1,500,292	A
Deduct: Charitable donations from Schedule 2	311	19,475		
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		19,475	► 19,475	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,480,817	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		1,480,817	
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)			1,480,817	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** 1,369,091 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** 1,480,817 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** *** 48,619 D / 11,250 = ... 1,728,676 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			1,480,817 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	131,201	G	
Total of amounts B, C, D, E, F, and G	131,201	▶	131,201 H
Amount A **minus** amount H (if negative, enter "0")			1,349,616 I

Amount I	1,349,616	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	1,349,616	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 %	=	114,717 K
Amount I	1,349,616	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	1,349,616	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 ..... 114,717 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** 131,201 x 26 2 / 3 % = ... 34,987 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") . . . . 34,987 C

Taxable income from line 360 1,480,817

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 = ______
______ ▶ ______

1,480,817
x 26 2 / 3 % = 394,885 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) 306,852
Deduct: Corporate surtax from line 600 . . . . ______
Net amount . . . . 306,852 ▶ 306,852 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** 34,987 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year **460** 108,152
Deduct: Dividend refund for the previous tax year **465** 108,152
______ ▶ ______ G

Add the total of:
Refundable portion of Part I tax from line 450 above 34,987
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** ______
34,987 ▶ 34,987 H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H **485** 34,987

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 . . . . 4,000,000 x 1 / 3 1,333,333 I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . 34,987 J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) 34,987

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . **550** 562,710 A

Corporate surtax calculation

Base amount from line A above	562,710	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	148,082	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	148,082	7
Net amount (line 1 **minus** line 7)	414,628	8

Corporate surtax*

Line 8 414,628 × Number of days in the tax year before January 1, 2008 ____ / Number of days in the tax year 366 × 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		131,201	i
Taxable income from line 360	1,480,817		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	1,480,817 ▶	1,480,817	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . **604** 8,747 D

Subtotal (**add** lines A, B, C, and D) 571,457 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	**608**	148,082	
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**	114,717	
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**	1,806	
Subtotal		264,605 ▶	264,605 F

Part I tax payable – Line E **minus** line F . . . . 306,852 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	306,852
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		306,852

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	306,852 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	34,987
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	271,865
Total credits	890	306,852 ► 306,852 B

Refund code 894 1 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . . 896 1 Yes ☐ 2 No ☒

Certification

I, 950 HURLEY (Last name in block letters) 951 PAT (First name in block letters) 954 OFFICER (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009-05-14 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (705) 326-7315 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 1 Yes ☒ 2 No ☐

958 ______ Name in block letters 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	7,295,722	
	Total tangible capital assets	2008	+	33,457,827	
	Total accumulated amortization of tangible capital assets	2009	–	17,570,456	
	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	=	23,183,093	
	Liabilities				
	Total current liabilities	3139	+	4,331,823	
	Total long-term liabilities	3450	+	11,417,749	
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	15,749,572	
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	7,433,521	
	Total liabilities and shareholder equity	3640	=	23,183,093	
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-3,153,463	

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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	+	29,031,491	
	Cost of sales	8518	–	28,077,538	
	Gross profit/loss	8519	=	953,953	
	Cost of sales	8518	+	28,077,538	
	Total operating expenses	9367	+	610,125	
	Total expenses (mandatory field)	9368	=	28,687,663	
	Total revenue (mandatory field)	8299	+	29,762,615	
	Total expenses (mandatory field)	9368	–	28,687,663	
	Net non-farming income	9369	=	1,074,952	
	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	=	1,074,952	
	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	–	473,000	
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	601,952	

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
Orillia Power Distribution Corporation	86512 0596 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				601,952 A
Add:				
Provision for income taxes – current		101	473,000	
Amortization of tangible assets		104	1,409,013	
Loss on disposal of assets		111	14,635	
Charitable donations and gifts from Schedule 2		112	19,475	
Non-deductible meals and entertainment expenses		121	9,036	
Reserves from financial statements – balance at the end of the year		126	1,103,589	
Subtotal of additions			3,028,748 ▶	3,028,748
Other additions:				
Miscellaneous other additions:				
603.2 Ontario Specified Tax Credits	5,773			
Total	5,773	293	5,773	
604.1 Federal Apprenticship Job Creation ITC	1,806			
Total	1,806	294	1,806	
Subtotal of other additions		199	7,579 ▶	7,579
Total additions		500	3,036,327 ▶	3,036,327
Deduct:				
Gain on disposal of assets per financial statements		401	10,655	
Capital cost allowance from Schedule 8		403	1,278,559	
Cumulative eligible capital deduction from Schedule 10		405	886	
Reserves from financial statements – balance at the beginning of the year		414	847,887	
Subtotal of deductions			2,137,987 ▶	2,137,987
Other deductions:				
Miscellaneous other deductions:				
Total		394		
Subtotal of other deductions		499	0 ▶	0
Total deductions		510	2,137,987 ▶	2,137,987
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,500,292

* For reference purposes only

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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)
Various	19,475
Subtotal	19,475
Add: Total donations of less than $100 each	
Total donations in current tax year	19,475

		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** 19,475				
Subtotal (line 250 **plus** line 210)		19,475	19,475	19,475
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		19,475 A	19,475	19,475
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	19,475	19,475	19,475
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 % .... 1,125,219 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) 1,125,219 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) .... 19,475 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 ________ × (B ________ / C) = Additional deduction for gifts of medicine for the current year **610** ________

Quebec

A ________ × (B ________ / C) = Additional deduction for gifts of medicine for the current year .... ________

Alberta

A ________ × (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.

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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
Orillia Power Distribution Corporation	86512 0596 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.

	A	B	Complete if payer corporation is connected		E
Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200		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	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	Business Number	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD	Taxable dividends paid to connected corporations
	400	**410**	**420**	**430**
1	Orillia Power Corporation	89197 8215 RC0001	2008-12-31	4,000,000
2				

Note

If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 4,000,000

Total taxable dividends paid in the taxation year to other than connected corporations **450**

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) **460** 4,000,000

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) **460** 4,000,000

Other dividends paid in the taxation year (total of 510 to 540) . . . .

Total dividends paid in the taxation year **500** 4,000,000

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 4,000,000

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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			1,500,292
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

	Line		
Non-capital loss at the end of the previous tax year			
Deduct: Non-capital loss expired *	100		
Non-capital losses at the beginning of the tax year	102		
Add: Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105		
Current-year non-capital loss (from calculation above)	110		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Deduct:			
Amount applied against taxable income (enter on line 331 of the T2 return)	130		
Amount applied against taxable dividends subject to Part IV tax	135		
		Subtotal	
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
Non-capital losses – Closing balance		180	

* A non-capital loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004.

Election under paragraph 88(1.1)(f)

Paragraph 88(1.1)(f) election indicator .... **190** Yes ☐

Loss from a wholly owned subsidiary deemed to be a loss of the parent from its immediately previous tax year.

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	**200**	30,460	
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	**205**		30,460
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	**250**		
Section 80 – Adjustments for forgiven amounts	**240**		
Add:		Subtotal	30,460
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	30,460

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	30,460

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** 30,460

Note 1

Enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2

On lines 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, multiply this amount by the 50% inclusion rate.

* Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004, and before 2006. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line A.

** Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004. Enter the full amount on line B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			
Deduct: Farm loss expired *	300		
Farm losses at the beginning of the tax year	302		
Add: Farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	305		
Current-year farm loss	310		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
Subtotal			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
Farm losses – Closing balance	380		

* A farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business	485		C
Minus the deductible farm loss:			
$2,500 plus D or E, whichever is less	$ 2,500		
(Amount C above ______ – $2,500) divided by 2 = ______	D		
$ 6,250	E	2,500	F
Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410)			

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired *	400		
Restricted farm losses at the beginning of the tax year	402		
Add: Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
Subtotal			
Deduct – Request to carry back restricted farm loss to:			
First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		
Restricted farm losses – Closing balance	480		

Note
The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			
Deduct: Listed personal property loss expired after seven tax years		500	
Listed personal property losses at the beginning of the tax year		502	
Add: Current-year listed personal property loss (from Schedule 6)		510	
		Subtotal	
Deduct:			
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530		
Other adjustments	550		
		Subtotal	
Deduct – Request to carry back listed personal property loss to:			
First previous tax year to reduce listed personal property gains	961		
Second previous tax year to reduce listed personal property gains	962		
Third previous tax year to reduce listed personal property gains	963		
Listed personal property losses – Closing balance		580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 - 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from prior tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year. (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 - 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

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SCHEDULE 7

CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2008-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part 1 Tax" in the *T2 Corporation – Income Tax Guide*.

Part 1 and Part 2 – Aggregate and foreign investment income calculation

	Canadian investment income	Foreign investment income	Aggregate investment income	
Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13				A1
Reserve's eligible portion (addition/deduction)				A2
Eligible portion of taxable capital gains included in the income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts A1 and A2)		001	002	A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		009	012	B
Net capital losses of other years claimed on line 332 on the T2 return			022	C
Total of amounts B and C				D
Amount A **minus** amount D (if negative, enter "0")				E
Total income from property (in box 32 include income from a specified investment business carried on in Canada other than income from a source outside Canada)				
Taxable dividends				
Other property income	131,201		131,201	
Total income from property	131,201	019	032 131,201	F
Exempt income		029	042	G
Amounts received from NISA Fund No. 2 (AGRI) that were included in computing the corporation's income for the year			052	H
Taxable dividends deductible (total of Column F on Schedule 3)		049	062	I
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		059	072	J
Total of amounts G, H, I, and J				K
Amount F **minus** amount K	131,201		131,201	L
Total of amount E **plus** amount L	131,201		131,201	M
Total losses from property (in box 82 include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)		069	082	N
Amount M **minus** amount N (if negative, enter "0")	131,201	079 L	092 O 131,201	

Note: The aggregate investment income is the aggregate world source income.

Enter amount L, foreign investment income, on line 445 of the T2 return.
Enter amount O, aggregate investment income, on line 440 of the T2 return.

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A	B	C
Partnership name **200**	Total income (loss) of partnership from an active business **300**	Corporation's share of amount in column B **310**

D	E	F	G	H	I
Adjustments [add prior-year reserves under subsection 34.2(5), and deduct expenses incurred to earn partnership income, including any reserve under subsection 34.2(4)] **315**	Corporation's income (loss) of the partnership (column C **plus** column D) **320**	Number of days in the partnership's fiscal period **325**	Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")** **330**	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") **340**
Total	**350**		Total	**385**	**360**

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount .... **370** ______

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) .... **380** ______

Total of lines 370 and 380 .... ______ ► ______ J

Amount at line 385 or line J, whichever is less .... **390** ______

Specified partnership income (line 360 **plus** line 390) .... **400** ______

* Use one of the following business limits to calculate column G, whichever applies:

- $250,000 if the corporation's tax year ends in 2004;
- $300,000 if the corporation's tax year ends in 2005 or 2006; or
- $400,000 if the corporation's tax year ends after 2006.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 above (if the net amount is negative, enter "0" on line O) .... ______ K

Add: Specified partnership loss (from line 380 above) .... ______ L

Subtotal ______ M

Deduct: Specified partnership income (from line 400 above) .... ______ N

Partnership income (enter on line S below) .... **450** ______ O

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return			1,500,292	P
Deduct: Foreign business income after deducting related expenses*	500			
Taxable capital gains **minus** allowable capital loss – amount A **minus** amount B* (page 1)**				
Net property income = amount F **minus** amount G, H, and N* (page 1)		131,201 Q		
Personal services business income after deducting related expenses*	520			
		131,201 ▶	131,201	
		Net amount	1,369,091	R
Deduct: Partnership income (line 450 above)				S
Income from active business carried on in Canada (enter on line 400 of the T2 return – if negative, enter "0")			1,369,091	T

* If negative, **add** instead of **subtracting.**
**This amount may only be negative to the extent of any allowable business investment losses.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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	3	Buildings	912,774			0		912,774	5	0	0	45,639	867,135
2	10		292,644	520,887		10,655	255,116	547,760	30	0	0	164,328	638,548
3	1	Distribution System	15,946,577	226,909		0	113,455	16,060,031	4	0	0	642,401	15,531,085
4	8	Office Furniture and Equipment	246,635	40,442		0	20,221	266,856	20	0	0	53,371	233,706
5	45	Computer Equipment Acquired at	11,262			0		11,262	45	0	0	5,068	6,194
6	46	Server Hardware	21,130			0		21,130	30	0	0	6,339	14,791
7	12	Application Software	7,270	218,330		0	109,165	116,435	100	0	0	116,435	109,165
8	47	Transmission and Distribution Ec	2,369,903	1,235,844		0	617,922	2,987,825	8	0	0	239,026	3,366,721
9	50	Computer Equipment Acquired A	7,434	6,774		0	3,387	10,821	55	0	0	5,952	8,256
		Total	19,815,629	2,249,186		10,655	1,119,266	20,934,894				1,278,559	20,775,601

* 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.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 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.	Orillia Power Generation Corporatio		86512 2998 RC0001	3					
2.	Orillia Power Corporation		89197 8215 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
Orillia Power Distribution Corporation	86512 0596 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** 7,901 A

Add: Cost of eligible capital property acquired during the taxation year **222** 6,342

Other adjustments **226**

Subtotal (line 222 plus line 226) 6,342 x 3 / 4 = 4,757 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") 4,757 ▶ 4,757 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 12,658 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) . . . . 12,658 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 12,658

less amount from line 249

Current year deduction . . . . 12,658 x 7.00 % = **250** 886 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 886 ▶ 886 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 11,772 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		**400**	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		**401**	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402**	3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408**	4		
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8		
Subtotal (line 7 plus line 8)	**409**	▶	9	
Line 6 minus line 9 (if negative, enter "0")			▶	O
Line N minus line O (if negative, enter "0")				P
Line 5		x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")				R
Amount R		x 2 / 3 =		S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)			**410**	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:
1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2008

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	Orillia Power Distribution Corporation	86512 0596 RC0001	1	400,000	100.0000	400,000	
2	Orillia Power Generation Corporation	86512 2998 RC0001	1	400,000			
3	Orillia Power Corporation	89197 8215 RC0001	1	400,000			
				Total	100.0000	400,000	A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

**The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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T2 CORPORATION INCOME TAX RETURN

200

EXEMPT FROM TAX

055 Do not use this area

PLEASE RETAIN THIS COPY FOR YOUR FILES

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** 86512 0596 RC0001

Corporation's name

002 Orillia Power Distribution Corporation

Has the corporation changed its name since the last time you filed your T2 return? **003** 1 Yes [ ] 2 No [X]

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 [X]
(If **yes**, complete lines 011 to 018)

011 360 West St S
012 P.O. Box 398

City	Province, territory, or state
015 Orillia	**016** ON
Country (other than Canada) **017**	Postal code/Zip code **018** L3V 6J9

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028)

021 c/o
022 P.O. 398
023

City	Province, territory, or state
025 Orillia	**026** ON
Country (other than Canada) **027**	Postal code/Zip code **028** L3V 6J9

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038)

031 360 West St S
032 P.O. Box 398

City	Province,territory, or state
035 Orillia	**036** ON
Country (other than Canada) **037**	Postal code/Zip code **038** L3V 6J9

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ________ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2008-01-01 (YYYY MM DD)   Tax year-end **061** 2008-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [X] Exempt under other paragraphs of section 149

Do not use this area

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	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201		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 [X]

Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers) 281 1 Yes [ ] 2 No [X]

What is the corporation's major business activity? 282
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale [ ] 2 Retail [ ]

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year? 291 1 Yes [ ] 2 No [X]

Did the corporation emigrate from Canada during the tax year? 292 1 Yes [ ] 2 No [X]

Do you want to be considered as a quarterly instalment remitter if you are eligible? 293 1 Yes [ ] 2 No [ ]

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any 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 ______ A

Deduct:

Charitable donations from Schedule 2	311	
Gifts to Canada, a province, or a territory from Schedule 2	312	
Cultural gifts from Schedule 2	313	
Ecological gifts from Schedule 2	314	
Gifts of medicine from Schedule 2	315	
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320	
Part VI.1 tax deduction *	325	
Non-capital losses of previous tax years from Schedule 4	331	
Net capital losses of previous tax years from Schedule 4	332	
Restricted farm losses of previous tax years from Schedule 4	333	
Farm losses of previous tax years from Schedule 4	334	
Limited partnership losses of previous tax years from Schedule 4	335	
Taxable capital gains or taxable dividends allocated from a central credit union	340	
Prospector's and grubstaker's shares	350	

Subtotal ______ ▶ ______ B

Subtotal (amount A **minus** amount B) (if negative, enter "0") ______ 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** ______ 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.

300,000	x	Number of days in the tax year in 2006 / Number of days in the tax year	___ / 366	=	______	1
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	366 / 366	=	400,000	2
			Add amounts at lines 1 and 2		400,000	4

Business limit (see notes 1 and 2 below) . . . . . **410** 400,000 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 x **415** *** ______ 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, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	17 %	= ______	6
Amount A, B, C, or F whichever is the least	______	x	Number of days in the tax year after December 31, 2008 / Number of days in the tax year	___ / 366	x	17 %	= ______	7

Total of amounts 5, 6, and 7 – enter on line 9 **430** ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . . . **435** ______ H

Amount H	______	x	Number of days in the tax year in 2006 / Number of days in the tax year	___ / 366	x	5 %	= ______	I
Amount H	______	x	Number of days in the tax year in 2007 / Number of days in the tax year	___ / 366	x	7 %	= ______	J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J . . . . . **438** ______ K
Enter amount K on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			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")			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
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 . . . . ________
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 . . . . ________ x 1 / 3 ________ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) . . . . ________

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 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 ______ 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 HURLEY (Last name in block letters) 951 PAT (First name in block letters) 954 OFFICER (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009-05-14 (Date (yyyy/mm/dd)) ______ Signature of the authorized signing officer of the corporation 956 (705) 326-7315 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☒ 2 No ☐

958 ______ Name in block letters 959 ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+		
	Total tangible capital assets	2008	+		
	Total accumulated amortization of tangible capital assets	2009	–		
	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	=		
	Liabilities				
	Total current liabilities	3139	+		
	Total long-term liabilities	3450	+		
	*Subordinated debt	3460	+		
	*Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=		
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+		
	Total liabilities and shareholder equity	3640	=		
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=		

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2008-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+		
	Cost of sales	8518	–		
	Gross profit/loss	8519	=		
	Cost of sales	8518	+		
	Total operating expenses	9367	+		
	Total expenses (mandatory field)	9368	=		
	Total revenue (mandatory field)	8299	+		
	Total expenses (mandatory field)	9368	–		
	Net non-farming income	9369	=		
	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	=		

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
Orillia Power Distribution Corporation	86512 0596 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.	Orillia Power Corporation		89197 8215 RC0001	1					
2.	Orillia Power Generation Corporatio		86512 2998 RC0001	3					

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

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 [X]

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	Orillia Power Distribution Corporation	86512 0596 RC0001	1	400,000	100.0000	400,000
2	Orillia Power Corporation	89197 8215 RC0001	1	400,000		
3	Orillia Power Generation Corporation	86512 2998 RC0001	1	400,000		
				Total	100.0000	400,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

**The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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 for Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

PLEASE RETAIN THIS COPY FOR YOUR FILES

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No

Corporation's Legal Name *(including punctuation)*: Orillia Power Distribution Corporation

Ontario Corporations Tax Account No. (MOF): 1800154

Mailing Address:
P.O. 398
Orillia
ON CA L3V 6J9

This Return covers the Taxation Year
Start (year month day): 2008-01-01
End (year month day): 2008-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes — Date of Change (year month day):

Date of Incorporation or Amalgamation (year month day): 2000-10-26

Registered/Head Office Address:
360 West St S
P.O. Box 398
Orillia
ON CA L3V 6J9

Ontario Corporation No. (MGS): 1446923

Location of Books and Records:
360 West St S
P.O. Box 398
Orillia
ON CA L3V 6J9

Canada Revenue Agency Business No. (If applicable, enter): 86512 0596 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
PAT HURLEY	(705) 326-7315	

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS):
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day):
Ceased (year month day):
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*: [X] English *anglais* [ ] French *français*

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s):

Ministry Use

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ [X] 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)*: PAT HURLEY

Title: D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired (year month day) ______

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
[ ]	[X]	the Carry-back of a Loss?
[X]	[ ]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.) ______

Ontario Employer Health Tax Account no. (Use head office no.) ______

Specify major business activity

Distribute Electric

ity

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	1,500,292
Subtract: Charitable donations	–	1	19,475
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ______ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	– From	704	
Net capital losses (page 16) From 715 ______ 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	1,480,817

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	1,480,817

Taxable Income

Number of Days in Taxation Year

From	Amount	Ontario Allocation	Rate	Days	Total Days		Line	Amount
10 (or 20 if applicable)	1,480,817	x 30 100.0000 %	x 12.5 %	x 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ______	÷ 73 366 (Total Days)	= +	29	
10 (or 20 if applicable)	1,480,817	x 30 100.0000 %	x 14 %	x 34 (Days after Dec. 31, 2003) 366	÷ 73 366 (Total Days)	= +	32	207,314

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 207,314

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) [X] Yes [ ] No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))			50	1,369,091
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	1,480,817		
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			
	=	1,480,817	▶ 54	1,480,817
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 (Least of 50 , 54 or 45) = 60 500,000

* *Note: Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** *Note: Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** *Note: Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate

Number of Days in Taxation Year

	Rate		Days		Total Days		Result
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 1,480,817

If you are a member of an associated group (X) 81 [X] (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
Orillia Power Generation Corporation	1800155	2008-12-31	+ 82	1,833,038
Orillia Power Corporation	1800153	2008-12-31	+ 83	
			+ 84	
Aggregate Taxable Income 80 + 82 + 83 + 84, etc.			= 85	3,313,855

Number of Days in Taxation Year

		Days		Total Days		Result
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 2,813,855

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 2,813,855 x From 97 4.2500 % = 87 119,589

From 87 119,589 x From 60 500,000 ÷ From 114 500,000 = 88 119,589

Surtax Lesser of 70 or 88 = 100 42,500

* ***Note: Short Taxation Years –*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

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 42,500 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 500,000
*Ontario Allocation

Lesser of 56 or 121	+		122	500,000
120 − 56 + 122	=		130	
Taxable Income	+	From	10	1,480,817
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	−	From	56	500,000
Add: Adjustments for Surtax on Canadian-controlled private corporations	+	From	122	500,000
Subtract: Taxable Income 10 1,480,817 X Allocation % to jurisdictions outside Canada	−		140	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses	−		141	131,201
10 − 56 + 122 − 140 − 141	=		142	1,349,616

Claim

Number of Days in Taxation Year

143 ______ (Lesser of 130 or 142) X From 30 100.0000 % (Ontario Allocation) X 1.5 % X [Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ______ ÷ Total Days: 73 366] = + 154 ______

143 ______ (Lesser of 130 or 142) X From 30 100.0000 % (Ontario Allocation) X 2 % X [Days after Dec. 31, 2003: 34 366 ÷ Total Days: 73 366] = + 156 ______

M&P claim for taxation year 154 + 156 = 160 ______

* ***Note:*** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

= 161 ______

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

= 162 ______

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170 ______

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 ______ Credit Claimed 180 ______

Subtotal of Income Tax

40 − 70 + 100 − 110 − 160 − 161 − 162 − 170 − 180 = 190 207,314

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)* + 192 773

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 1
Eligible Credit From 5898 CT23 Schedule 114 *(Attach Schedule 114)* + 203 5,000

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220 5,773

Specified Tax Credits ***Applied to reduce Income Tax*** = 225 5,773

Income Tax 190 − 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 201,541

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.**

DOLLARS ONLY

Total Assets of the corporation	+ 240	23,183,093
Total Revenue of the corporation	+ 241	29,762,615

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 [X] (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
Orillia Power Generation Corporation	1800155	2008-12-31	+ 243 10,547,457	+ 244 5,195,590
Orillia Power Corporation	1800153	2008-12-31	+ 245 14,721,460	+ 246 4,806,534
			+ 247	+ 248
Aggregate Total Assets 240 + 243 + 245 + 247, etc.			= 249 48,452,010	
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.				= 250 39,764,739

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 1,074,952 (If negative, enter zero) X From 30 100.0000 % (Ontario Allocation) X 4 % = 276 42,998

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	− 277	
Subtract: Income Tax	− From 190	207,314
Net CMT Payable (If negative, enter Nil on Page 17.)	= 280	-164,316

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	207,314
	Gross CMT Payable	+ From 276 42,998		
	Subtract: Foreign Tax Credit for CMT purposes	− From 277		
	If 276 − 277 is negative, enter NIL in 290	= 42,998	− 290	42,998
	Income Tax eligible for CMT Credit		= 300	164,316
B.	Income Tax (after deduction of specified credits)		+ From 230	201,541
	Subtract: CMT credit used to reduce income taxes		− 310	
	Income Tax		= 320	201,541 (*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.

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	8,235,883
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	-3,153,463
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	2,351,101
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	10,319,633
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	1,103,589
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	2,713,794
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	21,570,537
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	21,570,537
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	21,570,537

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	23,183,093
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	23,183,093
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	23,183,093

Investment Allowance (410 ÷ 450) x 390 — Not to exceed 410	=	460	
Taxable Capital 390 – 460	=	470	21,570,537

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	29,762,615
Total Assets (as adjusted)	From 430	23,183,093

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

Amount		Days		Total Days			
7,500,000	x	36 (Days after Dec. 31, 2004 and before Jan. 1, 2006)	÷ 73	366	= +	501	
10,000,000	x	37 (Days after Dec. 31, 2005 and before Jan. 1, 2007)	÷ 73	366	= +	502	
12,500,000	x	38 (Days after Dec. 31, 2006 and before Jan. 1, 2008)	÷ 73	366	= +	504	
15,000,000	x	39 (Days after Dec. 31, 2007) 366	÷ 73	366	= +	505	15,000,000

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 15,000,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

Rate		Days		Total Days			
0.3 %	x	556 (Days before Jan. 1, 2007)	÷ 73	366	= +	511	%
0.225 %	x	557 (Days after Dec. 31, 2006 and before Jan. 1, 2009) 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) *If floating taxation year, refer to Guide.* = + [523] ____________ *Transfer to [543] on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either [509] or [524] and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. [ ] [509] (X if applicable) All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital [470] on page 10 is equal to or less than the TCD [503] on page 10, enter NIL in [550] on page 12 and complete the return from that point.

If Taxable Capital [470] on page 10 exceeds the TCD [503] on page 10, proceed to **Section E**, enter the TCD amount in [542] in Section E, and complete Section E and the return from that point.

D2. [X] [524] (X if applicable) One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From [470] on page 10 - - - + From [470] 21,570,537 •

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
Orillia Power Generation Corporation	1800155	2008-12-31	+ [531]	•
Orillia Power Corporation	1800153	2008-12-31	+ [532]	4,370,778 •
			+ [533]	•
Aggregate Taxable Capital [470] + [531] + [532] + [533], etc.			= [540]	25,941,315 •

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] 21,570,537 • ÷ From [540] 25,941,315 • x From [503] 15,000,000 • = [541] 12,472,693 •

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]	21,570,537 •
−	[542]	12,472,693 •
=	[471]	9,097,844 •

[471] 9,097,844 • 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] 20,470 • **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]	20,470 •
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)*	− [546]	•
Capital Tax [543] − [546] *(amount cannot be negative)*	= [550]	20,470 •

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] 1,500,292 *Transfer to Page 15*

Add:

Federal capital cost allowance	+ 601	1,278,559
Federal cumulative eligible capital deduction	+ 602	886
Ontario taxable capital gain	+ 603	
Federal non-allowable reserves. Balance beginning of year	+ 604	847,887
Federal allowable reserves. Balance end of year	+ 605	
Ontario non-allowable reserves. Balance end of year	+ 606	1,103,589
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] ______ × 5 / 12.5 × [33] Days after Dec. 31, 2002 and before Jan. 1, 2004 ______ ÷ [73] Total Days 366 = + [633] ______

[612] ______ × 5 / 14 × [34] Days after Dec. 31, 2003 366 ÷ [73] Total Days 366 = + [634] ______

Total add-back amount for Management fees, etc. [633] + [634] = ______ + [613]

Federal Scientific Research Expenses claimed in year from line [460] of fed. form T661 excluding any negative amount in [473] from Ont. CT23 Schedule 161 + [615]

Add any negative amount in [473] from Ont. CT23 Schedule 161 + [616]

Federal allowable business investment loss + [620]

Total of other items not allowed by Ontario but allowed federally *(Attach schedule)* + [614]

Total of Additions [601] to [611] + [617] + [613] + [615] + [616] + [620] + [614] = 3,230,921 [640] 3,230,921 *Transfer to Page 15*

Deduct:

Ontario capital cost allowance (excludes amounts deducted under [675])	+ 650	1,278,559
Ontario cumulative eligible capital deduction	+ 651	886
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	847,887
Ontario allowable reserves. Balance end of year	+ 654	
Federal non-allowable reserves. Balance end of year	+ 655	1,103,589
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] 3,230,921 *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	1,500,292
Total of Additions on page 14	From =	640	3,230,921
Sub Total of deductions on page 14	From =	681	3,230,921

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 = 3,230,921 ▶ 680 3,230,921

Net income (loss) for Ontario Purposes 600 + 640 − 680 = 690 1,500,292

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) 30,460	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 30,460	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	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

Summary

Income Tax	+ From 230 or 320		201,541
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550		20,470
Premium Tax	+ From 590		
Total Tax Payable	=	950	222,011
Subtract: Payments	−	960	268,912
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	-46,901
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	=	975	46,901
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)*: PAT HURLEY

Title: OFFICER

Full Residence Address:

Signature:

Date: 2009-05-14

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2006 CT23 Short-Form Corporations Tax and Annual Return

For taxation years commencing after December 31, 2003

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 Short-Form 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 Short-Form Return** on pages 3-6. Corporations that **do not** meet the EFF criteria or the Short-Form criteria, must file the regular **CT23 return.**

The **Annual Return** (common page 1 and MGS Schedules A or K on pages 7 and 8) 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.

PLEASE RETAIN THIS COPY FOR YOUR FILES

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No

Corporation's Legal Name *(including punctuation)*
Orillia Power Distribution Corporation

Ontario Corporations Tax Account No. (MOF)
1800154

Mailing Address
P.O. 398
Orillia
ON CA L3V 6J9

This Return covers the Taxation Year
Start (year month day) 2008-01-01
End (year month day) 2008-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes
Date of Change (year month day)

Date of Incorporation or Amalgamation (year month day)
2000-10-26

Registered/Head Office Address
360 West St S
P.O. Box 398
Orillia
ON CA L3V 6J9

Ontario Corporation No. (MGS)
1446923

Location of Books and Records
360 West St S
P.O. Box 398
Orillia
ON CA L3V 6J9

Canada Revenue Agency Business No.
If applicable, enter
86512 0596 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
PAT HURLEY	(705) 326-7315	

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day)
Ceased (year month day)
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*
[X] 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). ▸ [X] 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)*
PAT HURLEY

Title: D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Taxation Year End
year month day
2008-12-31

Exempt From Filing (EFF) Corporations Tax Return Declaration

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)
Orillia Power Distribution Corporation	1800154

This EFF Declaration must be filed for each taxation year that the corporation is exempt from filing and must be filed within 6 months after the corporation's taxation year end.

Criteria for exempt from filing status:

Yes	No	
X		a) has filed a federal Income Tax Return (T2) with Canada Revenue Agency for the taxation year;
X		b) had no Ontario taxable income for the taxation year (subject to the provisions in Note 2 below);
X		c) had no Ontario Corporations Tax payable for the taxation year;
X		d) was a Canadian-controlled private corporation throughout the taxation year (i.e. generally a private corporation with 50% or more shares owned by Canadian residents as defined by the *Income Tax Act* (Canada));
X		e) had provided its Canada Revenue Agency business number to the Ministry of Finance; and
X		f) is **not** subject to the Corporate Minimum Tax (i.e. alone or as part of an associated group whose total assets exceed $5 million or whose total revenue exceeds $10 million for the taxation year).

Note 1: Filing of this declaration and the Annual Return does not constitute the filing of a Corporations Tax Return under section 75 of the *Corporations Tax Act*.

Note 2: The following loss situations will require otherwise EFF corporations to file a CT23 tax return complete with all related schedules and financial statements:

- If a corporation has a loss in the current taxation year that is to be carried back and applied to a previous taxation year(s), regardless of whether the loss is the same as for federal purposes or not, a CT23 tax return is required for the current taxation year. The corporation must also provide information indicating that the loss is to be carried back and specify the year and the amount of loss to be carried back to each taxation year.
- If a corporation has a prior year loss, that is not the same for both federal and Ontario purposes and the corporation is applying a loss carryforward from the prior year to the current year, a CT23 tax return is required for the current taxation year, and if not previously filed, a CT23 tax return for the prior taxation year in which the loss was incurred is also required. Although a tax return for the loss year is not required where the loss is not being applied, the ministry will accept the filing of a tax return for a loss year at the time the loss is incurred.
- If a corporation has a prior year loss, that is the same for both federal and Ontario purposes, but in the current taxation year the corporation is applying a different amount of loss for Ontario than the loss amount being applied for federal income tax purposes, the corporation is required to file a CT23 tax return for the current taxation year only.

The following 3 items MUST be completed for EFF declarations only. In cases where the Annual Return, which includes page 1, is **also** being filed, completion of these fields is **not** required.

1. Corporation's Mailing Address	2. Ontario Corporation No. (MGS)	3. Canada Revenue Agency Business No.
		If applicable, enter

(Please print name in full)

I, PAT HURLEY declare that:

The above corporation meets **all** of the exempt from filing criteria (a) through (f) above for the taxation year and therefore qualifies under the *Corporations Tax Act* as exempt from filing an Ontario Corporations Tax Return.

Signature	Title/Relationship to Corporation	Telephone Number	Date
	OFFICER	(705) 326-7315	2009-05-14

Please note that making a false statement to avoid compliance with the *Corporations Tax Act* is an offence which can result in a penalty and/or fine.

If you check "Yes" to ALL of the following criteria, you are eligible to file the CT23 Short-Form Corporations Tax Return.

Yes	No	
	X	a) The corporation is a Canadian-controlled private corporation (CCPC) throughout the taxation year. Indicate Share Capital with full voting rights owned by Canadian Residents (nearest whole percentage) 100 %
X		b) The corporation's taxable income for the taxation year is $200,000 or less. For a taxation year with less than 51 weeks, taxable income must be grossed-up. *(Refer to Guide.)*
	X	c) The corporation is **not** a member of a partnership/joint venture or a member of an associated group of corporations during the taxation year.
X		d) The corporation's taxation year ends on or after January 1, 2001, and its gross revenue and total assets are each $1,500,000 or less and the corporation is not a financial institution; or The corporation's taxation year commences after September 30, 2001, and its gross revenue and total assets are each $3,000,000 or less and the corporation is not a financial institution.
X		e) The corporation is **not** claiming a tax credit other than the Incentive Deduction for Small Business Corporations (IDSBC), Co-operative Education Tax Credit (CETC), Graduate Transitions Tax Credit (GTTC) or Apprenticeship Training Tax Credit (ATTC).
X		f) The corporation's Ontario allocation factor is 100%.

Note: Family Farm or Fishing corporations that have a taxation year ending on or after January 1, 2000 and are **not** subject to the Corporate Minimum Tax, may also use the **CT23 Short-Form Corporations Tax Return** if the corporation checks "Yes" to a), b), c), e) and f) above.

EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE

EXHIBIT 5 - TABLES

EXHIBIT 5 - APPENDICES

CAPITAL STRUCTURE

The purpose of Exhibit 5 is to summarize the method and cost of financing capital requirements for the 2010 test year. There have been no significant changes to OPDC's approach to capital structure since incorporation in 2000.

OPDC has a current deemed capital structure of 56.7% debt with a return of 7.25%, and 43.3% equity with a return of 9% as approved in the 2009 IRM rate decision EB-2008-0239. The deemed effective return on total rate base is currently 8.01%.

OPDC 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"). The deemed effective return on total rate base applied for is calculated at 7.52%.

Table 5-1 outlines the elements of OPDC's capital structure as required by the "Cost of Capital Report".

TABLE 5-1 ELEMENTS OF DEEMED CAPITAL STRUCTURE

Description	2006 EDR OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
DEEMED CAPITAL STRUCTURE - PERCENTAGE ALLOCATIONS						
Long-Term Debt - Deemed Percentage	50.00%	50.00%	50.00%	53.30%	56.70%	56.00%
Short-Term Debt - Deemed Percentage	0.00%	0.00%	0.00%	0.00%	0.00%	4.00%
All Debt - Deemed Percentage	**50.00%**	**50.00%**	**50.00%**	**53.30%**	**56.70%**	**60.00%**
Equity - Deemed Percentage	**50.00%**	**50.00%**	**50.00%**	**46.70%**	**43.30%**	**40.00%**
Total Deemed Capital Structure	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

COST OF CAPITAL

Return on Equity:

OPDC 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 February 24, 2009. OPDC understands that the OEB will be finalizing the ROE for 2010 rates based on January 2010 market interest rate information. OPDC'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

OPDC has a promissory note with the City of Orillia, its municipal shareholder, for $9,762,000. OPDC has no other long term debt. The promissory note was issued November 1, 2000 with a 30 year term which includes terms and conditions that 1/5 of the principal be called within any year with 6 months notice. Since the promissory note is with an affiliate and is callable OPDC is requesting a return on Long Term Debt for the 2010 Test Year of 7.62% in accordance with the Cost of Capital Report. OPDC understands the debt rate of 7.62% reflects the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on February 24, 2009 and that the OEB will be finalizing a equivalent debt rate for 2010 rates based on January 2010 market interest rate information. It is OPDC understanding that the OEB's updated long term debt rate would be applied to the deemed long term debt component of rate base.

Table 5-2 summarizes key financial details of the promissory note and a copy of the promissory note is included in Appendix 5-A.

TABLE 5-2 SUMMARY OF FINANCIAL DETAILS FOR CITY OF ORILLIA PROMISSORY NOTE

Description	2006 EDR OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
DETAILS OF ACTUAL LONG TERM DEBT HELD BY CITY OF ORILLIA						
Promissory Note City of Orillia (municipal shareholder)						
Issued November 1, 2000						
Principal callable 1/5 per year with 6 months notice						
Principal	9,762,000	9,762,000	9,762,000	9,762,000	9,762,000	9,762,000
Interest rate	7.25%	6.25%	6.25%	6.25%	6.25%	7.62%
Term in years	30	30	30	30	30	30
Annual interest paid	707,700	610,100	610,100	610,100	610,100	743,900

Cost of Debt: Short Term

OPDC 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 February 24, 2009. OPDC understands that the OEB will be finalizing the return on short term debt for 2010 rates based on January 2010 market interest rate information. OPDC'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 2009.

Return on Total Rate Base

Table 5-3 outlines OPDC's regulated return on total rate base assuming the deemed capital structure outlined in Exhibit 5 Tab 1 Schedule 1.

TABLE 5-3 COST COMPONENTS FOR DEEMED CAPITAL STRUCTURE

Description	2006 EDR OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
EFFECTIVE COST RATES FOR DEEMED CAPITAL STRUCTURE						
Long-Term Debt - Effective Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.62%
Short-Term Debt - Effective Rate	0.00%	0.00%	0.00%	0.00%	0.00%	1.33%
Total Debt - Weighted Effective Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.20%
Equity - Effective Rate	9.00%	9.00%	9.00%	9.00%	9.00%	8.01%
Weighted Regulated Rate of Return	**8.13%**	**8.13%**	**8.13%**	**8.07%**	**8.01%**	**7.52%**

CALCULATION OF DEEMED RETURN ON EQUITY AND DEEMED COST OF DEBT

Table 5-4 applies the deemed debt/equity ratios and deemed rates of return to the rate base calculated in Exhibit 6 Tables 6-2 and 6-3 for 2006, 2007, 2008, 2009 Bridge and 2010 Test Year Forecast. The proposed distribution rates in this application assume the 2010 Test Year rate of return on rate base is 7.52%.

TABLE 5-4 ALLOWED (DEEMED) RATE OF RETURN AND COST OF DEBT

Description	2006 EDR OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
DEEMED CAPITAL STRUCTURE - PERCENTAGE ALLOCATIONS						
Long-Term Debt - Deemed Percentage	50.00%	50.00%	50.00%	53.30%	56.70%	56.00%
Short-Term Debt - Deemed Percentage	0.00%	0.00%	0.00%	0.00%	0.00%	4.00%
All Debt - Deemed Percentage	**50.00%**	**50.00%**	**50.00%**	**53.30%**	**56.70%**	**60.00%**
Equity - Deemed Percentage	**50.00%**	**50.00%**	**50.00%**	**46.70%**	**43.30%**	**40.00%**
Total Deemed Capital Structure	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
DEEMED CAPITAL STRUCTURE - EFFECTIVE RATES						
Long-Term Debt - Effective Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.62%
Short-Term Debt - Effective Rate	0.00%	0.00%	0.00%	0.00%	0.00%	1.33%
Total Debt - Weighted Effective Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.20%
Equity - Effective Rate	9.00%	9.00%	9.00%	9.00%	9.00%	8.01%
Weighted Regulated Rate of Return	**8.13%**	**8.13%**	**8.13%**	**8.07%**	**8.01%**	**7.52%**
RATE BASE						
Rate Base	**18,115,300**	**19,064,500**	**19,205,400**	**19,462,100**	**20,227,700**	**20,743,200**
DEEMED CAPITAL STRUCTURE BASED ON REGULATED RATE BASE						
Long-Term Debt	9,057,700	9,532,300	9,602,700	10,373,300	11,469,100	11,616,200
Short-Term Debt	-	-	-	-	-	829,700
Total DebT	9,057,700	9,532,300	9,602,700	10,373,300	11,469,100	12,445,900
Equity	9,057,600	9,532,200	9,602,700	9,088,800	8,758,600	8,297,300
Deemed Rate Base	**18,115,300**	**19,064,500**	**19,205,400**	**19,462,100**	**20,227,700**	**20,743,200**
DEEMED RETURN ON RATE BASE						
Deemed Interest	656,700	691,100	696,200	752,100	831,500	896,200
Return on Equity	815,200	857,900	864,200	818,000	788,300	664,600
Return on Rate Base	**1,471,900**	**1,549,000**	**1,560,400**	**1,570,100**	**1,619,800**	**1,560,800**

APPENDIX 5 – A

A copy of the City of Orillia Promissory Note follows on the next two pages.

COPY

PROMISSORY NOTE

Principal Amount: $9,762,000.00 **Due: December 31, 2030**

Orillia, Ontario
November 1, 2000

For value received, the undersigned promises to pay to the order of The Corporation of the City of Orillia (the "City") at Orillia, Ontario, the sum of $9,762,000.00 together with interest calculated at the rate of 7.5% per annum to December 31, 2005 and thereafter together with interest at a rate which will be set for each subsequent 5 year period to be equal to 2% plus the annual rate paid by the Royal Bank of Canada (RBC) as set by the RBC head office in Toronto on December 31st of the year immediately preceding the commencement of each 5 year period on 270 day term deposits exceeding $8,000,000.00 (such $8,000,000.00 amount to be adjusted from time to time after December 31, 2000 to reflect the impact of inflation as measured by the Consumer Price Index 1996 Classification for Canada). Payments of interest shall be made by the undersigned quarterly on the last days of March, June, September and December in each year and interest shall commence to accrue on the date that the initial Performance Based Regulation rates set by the Ontario Energy Board for the undersigned become effective with the first payment of interest to become due and payable on the first quarterly payment date next following the interest commencement date. For greater certainty on October 11, 2000 the rate paid by RBC on a 270 day term deposit for $8,000,000.00 was 5.5% and the Consumer Price Index 1996 Classification for Canada was 114.4.

In addition to the payment of interest as hereinbefore set out the undersigned shall pay to the City on March 31st in any calendar year, upon the City giving to the undersigned at least 6 months prior written notice, a prepayment of up to 20% of the original principal amount of this Promissory Note. The undersigned shall not have the right to prepay the principal in whole or in part at any time other than as required by the City herein.

In the event that the undersigned defaults in making any payments of principal or interest due under this Promissory Note and such default has not been corrected within 30 days after the City has given written Notice to the undersigned of such default, then the City may, at its option, demand immediate payment of all principal and interest due under this Promissory Note.

Any Notice which may be given to the undersigned or the City pursuant to this Promissory Note shall be given in writing at the following addresses:

To: Orillia Power Distribution Corporation
360 West Street South
P.O. Box 398
Orillia, Ontario
L3V 6J9

To: The Corporation of the City of Orillia
50 Andrew Street South
Orillia, Ontario
L3V 7T5
Attention: Clerk

Either party may change its address by giving notice of the change to the other party. Any Notice provided for herein shall be given by prepaid registered mail and shall be deemed to have been given and received on the 5th day after mailing.

ORILLIA POWER DISTRIBUTION
CORPORATION

Name: John Mattinson
Title: President
I have authority to bind the Corporation.

COPY

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)
2010 ELECTRICITY DISTRIBUTION RATES APPLICATION
EB-2009-0273
EFFECTIVE MAY 1, 2010

EXHIBIT 6 - CALCULATION OF REVENUE DEFICIENCY

EXHIBIT 6 - TABLES

CALCULATION OF REVENUE DEFICIENCY AND RETURN ON EQUITY

The information and tables provided in Exhibit 6 support OPDC's request in this application for an increase in its revenue requirement that will support its proposed capital and operating budgets for 2010, service its debt, pay deemed income taxes (PILS) and earn its allowed return on equity. As outlined in Table 6-1, OPDC has calculated its revenue deficiency for the 2010 Test Year at existing 2009 OEB-approved rates to be $671,200 net of taxes. When grossed up for PILs, OPDC's revenue deficiency is $955,200.

As indicated in exhibit 5, OPDC 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 February 24, 2009. OPDC understands that the OEB will be finalizing the ROE for 2010 rates based on January 2010 market interest rate information. OPDC'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.

The revenue deficiency calculation only includes items related to the distribution of electricity. The costs included in the revenue deficiency are based on OPDC's approved 2010 Operations budget for distribution operations and maintenance, billing and administration costs.

The calculation does not included any recoveries or repayments of regulatory assets, low voltage charges, the approved smart meter funding adder and other electricity charges such as energy commodity, transmission charges and wholesale market service charges.

CAUSES OF REVENUE DEFICIENCY:

The revenue deficiency is primarily the result of:

- Increases in operations, maintenance and administrative costs including depreciation expense since rates were last rebased. Drivers for the increases are outlined in detail in Exhibit 4.

- Capital Expenditures from 2004 through 2010 have significantly exceeded depreciation levels resulting in increased rate base on which the rate of return is calculated. Changes in the Rate Base are discussed in detail in Exhibit 2.

Further to the increases alluded to above, OPDC discovered that a significant error in OPDC's 2006 EDR filing had been made while examining variances between controllable costs in 2006 Actual and 2006 EDR. This error is explained in detail in Exhibit 4 Tab 3 Schedule 1. **The correction of this omission in distribution costs in the 2006 EDR accounts for almost 40% of the after tax revenue deficiency outlined in Table 1-10 below.**

Table 6-1: REVENUE DEFICIENCY

Description	2010 Test Revenues at Existing Rates	2010 Test Revenues at Proposed Rates
REVENUES		
Distribution Revenues - existing rates	$6,161,700	6,161,700
Other Operating and Interest Revenue	541,300	541,300
Revenue Deficiency - After Taxes Assuming Existing Rates Maintained	-	**671,200**
Revenue Deficiency - Increase required to pay additional taxes	-	**284,000**
Total Revenues	**6,703,000**	**7,658,200**
DISTRIBUTION COSTS		
Operations & Maintenance, Administrative & General, Billing & Collections	4,346,000	4,346,000
Depreciation & Amortization	1,449,000	1,449,000
Deemed Interest	896,200	896,200
Total Costs and Expenses	**6,691,200**	**6,691,200**
UTILITY EARNINGS AFTER PILS		
Utility Earnings Before PILS	11,800	967,000
Payments in lieu of income taxes (PILS)	18,400	302,400
Utility Net Earnings	**(6,600)**	**664,600**

REVENUE DEFICIENCY ASSUMING EXISTING RATES MAINTAINED		
Utility Net Earnings - Proposed Rates	664,600	-
Utility Net Earnings - Assuming Existing Rates Maintained	(6,600)	-
Revenue Deficiency After Tax - Assuming Existing Rates Maintained	**671,200**	-
Revenue Deficiency Before Tax - Assuming Existing Rates Maintained	-	**955,200**

Table 6-2 outlines the return on equity and return on rate base calculations based on 2010 revenues calculated first using existing rates and second using proposed rates. The calculations assume deemed interest is paid in both cases and PILS are calculated based on the income levels achieved.

If existing rates remain unchanged for 2010, OPDC's return on equity is negative 0.08% and return on rate base is 4.29%. Under the proposed rate structure in this application, OPDC's return on equity is restored to the regulatory allowed (or deemed) rate of return of 8.01% and return on rate base is restored to the deemed rate of 7.52%.

Table 6-2: RETURN ON EQUITY AND RETURN ON RATE BASE

Description	2010 Test Revenues at Existing Rates	2010 Test Revenues at Proposed Rates
TOTAL RATE BASE AND DEEMED EQUITY PORTION USED FOR RETURN CALCULATIONS		
Total Rate Base	20,743,200	20,743,200
Percentage Portion of rate base deemed to be equity	40.00%	40.00%
Deemed Equity Portion of Rate Base	8,297,300	8,297,300
RETURN ON EQUITY		
Utility Net Earnings	(6,600)	664,600
Deemed Equity Portion of Rate Base	8,297,300	8,297,300
Return On Equity	**-0.08%**	**8.01%**
RETURN ON TOTAL RATE BASE		
Utility Net Earnings plus Deemed Interest	889,600	1,560,800
Total Rate Base	20,743,200	20,743,200
Return On Rate Base	**4.29%**	**7.52%**

DETERMINATION OF BASE DISTRIBUTION REVENUE REQUIREMENT

Table 6-3 shows OPDC's total revenue requirement and base revenue requirement. Orillia Power Distribution's total revenue requirement is comprised of the following components:

- Distribution Operations and Maintenance expense
- Administration expense including billing and collection costs for 2010
- PILS – Income taxes
- Deemed Return on Rate Base (Interest expense on debt plus return on equity).

The total revenue requirement is then offset by other operating revenues received from OEB approved specific service charges as outlined in Exhibit 3 such as late payment charges, collection charges etc. The net amount or OPDC's base revenue requirement is then used to determine class specific distribution rates.

Table 6-3: CALCULATION OF TOTAL AND BASE REVENUE REQUIREMENT FOR 2010

Description	2010 Test
Distribution Operation & Maintenance	$1,823,000
Administrative & General, Billing & Collections	$2,523,000
Depreciation & Amortization	$1,449,000
Deemed Interest	$896,200
PILs	$302,400
Return on Equity	$664,600
Service Revenue Requirement	**$7,658,200**
Less: Revenue Offsets	$541,300
Base Revenue Requirement	**$7,116,900**

DETERMINATION OF RATE BASE

Tables 6-4 and 6-5 indicate how OPDC's determination of rate base was arrived at.

Table 6-4 calculates a working capital allowance amount based on 15% of distribution operations and maintenance, billing and general administration expenses plus cost of power for 2010.

Table 6-5 calculates OPDC's rate base by adding the working capital allowance to the average net book value of distribution assets for 2010. OPDC's rate base is expected to be $20,743,200 based on its planned operations and capital expenditures budgets for 2010.

Table 6-4: WORKING CAPITAL EXPENSES SUMMARY

Description	2010 Test
SUMMARY OF COMPONENTS FOR DEEMED WORKING CAPITAL CALCULATION	
Distribution Operations	1,037,000
Distribution Maintenance	786,000
Distribution Maintenance & Operations	**1,823,000**
Billing & Collection	1,041,000
Community Relations	21,000
Administration & General	1,422,000
Taxes Other Than Income Taxes(includes capital taxes)	33,000
Other Deductions	6,000
Billing & Collection, General & Administration	**2,523,000**
Cost of Power	23,732,000
Components for Working Capital Calculation	**28,078,000**
Working Capital Allowance @ 15% of above	**4,211,700**

Table 6-5: CALCULATION OF RATE BASE FOR 2010

Description	2009 Bridge	2010 Test
SUMMARY OF COMPONENTS FOR DEEMED RATE BASE CALCULATION		
Gross Property Plant and Equipment	35,387,000	37,101,000
Accumulated Amortization	18,988,000	20,437,000
Net Book Value of Total Property Plant & Equipment	**16,399,000**	**16,664,000**
(A) Average Net Book Value - LDC Operations		**16,531,500**
Working Capital Expenses		28,078,000
(B) Working Capital Allowance @ 15%		**4,211,700**
Rate Base (A) + (B)		**20,743,200**

Table 6-6 outlines OPDC's calculation for allowed (deemed) rate of return on rate base for the 2010 test year. Application of the deemed weighted debt rate of 7.2% and the deemed return on equity rate to the rate base results in a total return on rate base of $1,568,000. Included in that figure is $664,600 for return on the equity portion used to determine revenue deficiency at existing rates.

Table 6-6: ALLOWED (DEEMED) RATES OF RETURN FOR 2010

Description	2010 Test
DEEMED CAPITAL STRUCTURE - PERCENTAGE ALLOCATIONS	
Long-Term Debt - Deemed Percentage	56.00%
Short-Term Debt - Deemed Percentage	4.00%
All Debt - Deemed Percentage	**60.00%**
Equity - Deemed Percentage	**40.00%**
Total Deemed Capital Structure	100.00%
DEEMED CAPITAL STRUCTURE - EFFECTIVE RATES	
Long-Term Debt - Effective Rate	7.62%
Short-Term Debt - Effective Rate	1.33%
Total Debt - Weighted Effective Rate	7.20%
Equity - Effective Rate	8.01%
Weighted Regulated Rate of Return	**7.52%**
RATE BASE	
Rate Base	**20,743,200**
DEEMED CAPITAL STRUCTURE BASED ON REGULATED RATE BASE	
Long-Term Debt	11,616,200
Short-Term Debt	829,700
Total DebT	12,445,900
Equity	8,297,300
Deemed Rate Base	**20,743,200**
DEEMED RETURN ON RATE BASE	
Deemed Interest	896,200
Return on Equity	664,600
Return on Rate Base	**1,560,800**

EXHIBIT 7 - COST ALLOCATION

Schedule No.

TAB 1 _ Cost Allocation Study Requirements

EXHIBIT 7 - TABLES

EXHIBIT 7 - APPENDICES

COST ALLOCATION STUDY OVERVIEW:

On September 29, 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. OPDC prepared a cost allocation information filing consistent with OPDC’s understanding of the Directions, the Guidelines, the Model and the Instructions. OPDC 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.

For the purposes of this Application, OPDC has updated the cost allocation study previously filed to reflect 2010 test year costs, customer numbers and demand values. The 2010 demand values are based on the weather normalized load forecast used to design rates. OPDC has also removed the “cost” and "revenue" associated with transformer ownership allowance from the updated cost allocation study.

PROPOSED CHANGES TO MODEL

The data used in the updated cost allocation study is consistent with OPDC's cost data that supports the proposed 2010 revenue requirement outlined in this application. Consistent with the Guidelines, OPDC's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing. 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 OPDC, its engineering records, and its customer and financial information systems. An Excel version of the updated cost allocation study has been included in Appendix 7-A.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2010 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2010 customer forecast outlined in Exhibit 3 Tab 1. The load profiles for each rate class are the same as those used in the original information filing but have been scaled to match the load forecast. Table 7-1 outlines the scaling factors used by rate class.

Table 7-1: Load Profile Scaling Percentages

Rate Class	2004 Weather Normal Values (kWh) used in Informational Filing	2010 Weather Normal Values (KWh)	Scaling Factor
Residential	113,966,578	108,676,163	95.4%
GS <50 kW	51,401,760	48,230,452	93.8%
GS>=50 kW	162,317,415	150,956,406	93.0%
Street Light	2,620,771	2,560,651	97.7%
Sentinel	443,444	324,773	73.2%
Unmetered Scattered Load	1,460,732	822,688	56.3%
Total	**332,210,700**	**311,571,133**	**93.8%**

REVENUE TO COST RATIOS

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.

Table 7-2 outlines the revenue to cost ratios from the updated cost allocation study.

Sheet "O1 - Revenue to Cost Summary Worksheet" from the updated cost allocation study has been attached as Appendix 7-A.

Table 7-2: 2010 Revenue to Cost Ratios

Class	Total Revenue Requirement 2010 Cost Allocation	2010 Distribution Revenues Allocated based on Proportion of Revenue at Existing Rates	2010 Current Miscellaneous Revenue Allocated as per Cost Allocation Model	2010 Revenue Requirement Before Adjustment	Revenue to Cost Ratio
Residential	$4,268,709	$3,628,316	$355,859	$3,984,174	93.3%
GS <50 kW	$1,319,649	$1,341,448	$92,184	$1,433,632	108.6%
GS>=50 kW	$1,606,100	$2,003,367	$84,965	$2,088,331	130.0%
Street Light	$417,455	$81,185	$6,582	$87,767	21.0%
Sentinel	$24,414	$17,262	$1,020	$18,282	74.9%
Unmetered Load	$21,873	$45,323	$691	$46,014	210.4%
TOTALS	**$7,658,200**	**$7,116,900**	**$541,300**	**$7,658,200**	**100.0%**

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 7-3 below. In addition Table 7-3 provides OPDC’s proposed 2010 revenue to cost ratios. The proposed revenue to cost ratios reflect adjustments to revenue to address cross subsidization.

Table 7-3 also provides the revenue to cost ratios from the initial cost allocation study and the initial cost allocation study revised to remove the “cost” and "revenue" associated with transformer ownership allowance.

Table 7-3: Revenue to Cost Ratios Comparative Results

Class	Initial Cost Allocation Study	Initial Cost Allocation Study Revised for Transformer Allowance	2010 Cost Allocation Study	Proposed Revenue to Cost Ratio	Board Targets Minimum to Maximum	
Residential	91.2%	93.1%	93.3%	**93.3%**	85%	115%
GS <50 kW	98.1%	100.6%	108.6%	**108.6%**	80%	120%
GS>=50 kW	148.3%	140.0%	130.0%	**125.2%**	80%	180%
Street Light	20.8%	21.5%	21.0%	**45.5%**	70%	120%
Sentinel	72.3%	74.5%	74.9%	**74.9%**	70%	120%
Unmetered Load	201.4%	208.4%	210.4%	**100.0%**	80%	120%

OPDC 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 the street light class to 50% between their current ratio and the target ratio. The current revenue to cost ratio for street lights is 21.0% moving the ratio to 45.5% means the proposed ratio is half way between 21.0% 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 the General Service > 50 kW class since the revenue to cost ratio for this class is the highest. The reallocation of revenue to the General Service > 50 kW class reduces the revenue to cost ratio to this class but it still remains to be the highest.

Summary:

OPDC submits that the proposed reallocation of distribution revenue across customer classes is fair and reasonable. In this rate application, the process of moving toward revenue to cost ratios of 100% and reducing cross-subsidization has begun. Customer class revenues will more closely reflect the actual costs of providing distribution service to that class as indicated in the cost allocation model.

While the revenue to cost ratios are not yet perfectly aligned, partial reallocation provides time for further refinement of the model and more movement between classes in the future. The ratios for the classes that appear to be most out of line with the guidelines have been moved in the proper direction without too dramatic an impact (street lighting being the exception). As the industry gains experience with the cost allocation model and it is refined and improved further, more movement will be possible and warranted at that time.

APPENDIX 7 – A

A copy of Sheet O1 – Revenue to Cost Summary Worksheet follows on the next page.

2010 COST ALLOCATION STUDY
Orillia Power Distribution Corporation
EB-2009-0273
Wednesday, September 16, 2009
Sheet O1 Revenue to Cost Summary Worksheet -

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$7,116,900	$3,628,316	$1,341,448	$2,003,367	$81,185	$17,262	$45,323
mi	Miscellaneous Revenue (mi)	$541,300	$355,859	$92,184	$84,965	$6,582	$1,020	$691
	Total Revenue	$7,658,200	$3,984,174	$1,433,632	$2,088,331	$87,767	$18,282	$46,014
	Expenses							
di	Distribution Costs (di)	$1,783,000	$940,629	$292,901	$414,396	$122,131	$6,697	$6,245
cu	Customer Related Costs (cu)	$1,081,000	$780,005	$191,790	$106,961	$612	$1,046	$586
ad	General and Administration (ad)	$1,482,000	$884,649	$251,031	$273,667	$64,990	$4,068	$3,595
dep	Depreciation and Amortization (dep)	$1,449,000	$731,715	$260,792	$342,720	$103,027	$5,651	$5,096
INPUT	PILs (INPUT)	$302,400	$151,218	$52,445	$76,015	$20,563	$1,128	$1,031
INT	Interest	$896,200	$448,154	$155,428	$225,279	$60,940	$3,344	$3,055
	Total Expenses	$6,993,600	$3,936,369	$1,204,388	$1,439,039	$372,263	$21,934	$19,607
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$664,600	$332,340	$115,262	$167,061	$45,192	$2,480	$2,265
	Revenue Requirement (includes NI)	$7,658,200	$4,268,709	$1,319,649	$1,606,100	$417,455	$24,414	$21,873
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$30,427,500	$15,197,041	$5,569,834	$7,367,721	$2,075,558	$113,860	$103,486
gp	General Plant - Gross	$6,187,500	$3,102,988	$1,069,114	$1,538,506	$431,688	$23,687	$21,517
accum dep	Accumulated Depreciation	($19,712,500)	($9,823,543)	($3,718,432)	($4,703,464)	($1,327,996)	($72,841)	($66,225)
co	Capital Contribution	($371,000)	($206,928)	($54,720)	($52,572)	($51,657)	($2,833)	($2,290)
	Total Net Plant	$16,531,500	$8,269,558	$2,865,796	$4,150,191	$1,127,594	$61,874	$56,487
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$23,732,000	$8,277,733	$3,673,656	$11,498,169	$195,042	$24,738	$62,663
	OM&A Expenses	$4,346,000	$2,605,283	$735,722	$795,025	$187,734	$11,811	$10,426
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$28,078,000*	*$10,883,016*	*$4,409,378*	*$12,293,194*	*$382,775*	*$36,548*	*$73,089*
	Working Capital	$4,211,700	$1,632,452	$661,407	$1,843,979	$57,416	$5,482	$10,963
	Total Rate Base	$20,743,200	$9,902,011	$3,527,202	$5,994,170	$1,185,010	$67,356	$67,451
		Rate Base Input equals Output						
	Equity Component of Rate Base	$8,297,280	$3,960,804	$1,410,881	$2,397,668	$474,004	$26,942	$26,980
	Net Income on Allocated Assets	$664,600	$47,805	$229,244	$649,293	($284,497)	($3,652)	$26,406
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$664,600	$47,805	$229,244	$649,293	($284,497)	($3,652)	$26,406
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	93.33%	108.64%	130.02%	21.02%	74.88%	210.37%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	($284,535)	$113,982	$482,231	($329,688)	($6,132)	$24,141
	RETURN ON EQUITY COMPONENT OF RATE BAS	8.01%	1.21%	16.25%	27.08%	-60.02%	-13.55%	97.87%

ORILLIA POWER DISTRIBUTION CORPORATION (OPDC)

2010 ELECTRICITY DISTRIBUTION RATES APPLICATION

EB-2009-0273

EFFECTIVE MAY 1, 2010

ORILLIAPOWER

Energizing Our Community

EXHIBIT 8 - RATE DESIGN

Schedule No.

EXHIBIT 8 - TABLES

EXHIBIT 8 - TABLES (continued)

EXHIBIT 8 - GRAPHS

EXHIBIT 8 - APPENDICES

RATE DESIGN OVERVIEW

This Exhibit documents the calculation of OPDC's proposed distribution rates by rate class for the 2010 test year, based on the rate design as proposed in this Exhibit.

OPDC has determined its total 2010 service revenue requirement to be $7,658,200. Other revenues in the amount of $541,300 serve to reduce OPDC's total service revenue requirement to a base revenue requirement to $7,116,900 which is used to determine the proposed distribution rates. The base revenue requirement is derived from OPDC's 2010 capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The base revenue requirement is summarized in Table 8-1 below:

TABLE 8-1: Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	$4,346,000
Amortization Expenses	$1,449,000
Regulated Return On Capital	$1,560,800
PILs	$302,400
Service Revenue Requirement	**$7,658,200**
Less: Revenue Offsets	$541,300
Base Revenue Requirement	**$7,116,900**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Table 7-3 in Exhibit 7. Table 8-2 shows how the base revenue requirement has been allocated to the rate classes.

TABLE 8-2: Proposed Apportionment of Base Revenue to Rate Classes

Rate Classification	Total Revenue Requirement 2010 Cost Allocation	2010 Proposed Revenue to Cost Ratio	2010 Proposed Service Revenue Requirement	2010 Proposed Misc. Revenue Allocated as per Cost Allocation Model	2010 Proposed Base Revenue Requirement
Residential	$4,268,709	93.3%	$3,984,174	$355,859	$3,628,316
GS <50 kW	$1,319,649	108.6%	$1,433,632	$92,184	$1,341,448
GS>=50 kW	$1,606,100	125.2%	$2,010,246	$84,965	$1,925,281
Street Light	$417,455	45.5%	$189,993	$6,582	$183,411
Sentinel	$24,414	74.9%	$18,282	$1,020	$17,262
Unmetered Scattered Load	$21,873	100.0%	$21,873	$691	$21,182
Total	**$7,658,200**		**$7,658,200**	**$541,300**	**$7,116,900**

Table 8-3 provides the movement in revenue at existing rates for base revenue requirement to the proposed base revenue requirement which reflects the proposed revenue to cost ratios.

TABLE 8-3: Test Year Base Revenue Impacts

Rate Classification	2010 Total Base Revenue with 2009 Approved Rates	2010 Distribution Base Revenues Allocated based on Proportion of Revenue at Existing Rates	2010 Proposed Base Revenue Requirement
Residential	$3,141,334	$3,628,316	$3,628,316
GS <50 kW	$1,161,403	$1,341,448	$1,341,448
GS>=50 kW	$1,734,481	$2,003,367	$1,925,281
Street Light	$70,288	$81,185	$183,411
Sentinel	$14,946	$17,262	$17,262
Unmetered Scattered Load	$39,240	$45,323	$21,182
Total	**$6,161,692**	**$7,116,900**	**$7,116,900**

DETERMINATION OF MONTHLY FIXED CHARGES

Based on applying the existing approved monthly service charges (excluding the smart meter adder) to the forecasted number of customers for 2010 and applying the existing approved distribution volumetric charge (excluding the adjustment for LV and transformation allowance) to 2010 forecasted volumes the following Table 8-4 outlines the OPDC's current split between fixed and variable distribution revenue.

TABLE 8-4: Current Fixed Variable Split

Rate Classification	2010 Fixed Base Revenue with 2009 Approved Rates	2010 Variable Base Revenue with 2009 Approved Rates	2010 Total Base Revenue with 2009 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$1,826,353	$1,314,982	$3,141,334	58.1%	41.9%
GS <50 kW	$500,645	$660,757	$1,161,403	43.1%	56.9%
GS>=50 kW	$636,867	$1,097,614	$1,734,481	36.7%	63.3%
Street Light	$45,232	$25,056	$70,288	64.4%	35.6%
Sentinel	$7,465	$7,481	$14,946	49.9%	50.1%
Unmetered Scattered Load	$27,887	$11,353	$39,240	71.1%	28.9%
Total	**$3,044,449**	**$3,117,242**	**$6,161,692**		

OPDC submits that it is appropriate for 2010 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications. In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, 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.

On 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". OPDC's MSCs exceed that floor amount by rate class. 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-2008-0031).

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. In regards to possible MSC's and in accordance with the filing requirements the following information has been provided in Table 8-5.

TABLE 8-5: Monthly Service Charge Information from Cost Allocation Model

Rate Classification	2009 Monthly Service Charge Excluding Smart Meter Adder	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per month - Minimum System with PLCC Adjustment
Residential	$13.34	$4.60	$13.43
GS <50 kW	$30.79	$13.60	$25.40
GS>=50 kW	$338.04	$11.70	$61.86
Street Light	$1.06	-$0.13	$9.63
Sentinel	$3.19	$0.28	$10.00
Unmetered Scattered Load	$15.39	$0.14	$7.08

Until the OEB's Rate Review proceeding (EB-2008-0031) is completed and consistent with many 2008 and 2009 approved cost of service rate applications, it is OPDC's view that a MSC ceiling has not been established and it is appropriate for the purposes of setting rates in this application to maintain the current fixed and variable proportions of its 2009 rates. Changes in MSCs are due solely to changes in the total base revenue requirement attributable to each customer class. The following Table 8-6 provides OPDC'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 8-6: Proposed Monthly Service Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue Proportion	Annualized Customers / Connections	Proposed Fixed Distribution Charge
Residential	$3,628,316	58.1%	136,908	$15.41
GS <50 kW	$1,341,448	43.1%	16,260	$35.56
GS>=50 kW	$1,925,281	36.7%	1,884	$375.23
Street Light	$183,411	64.4%	42,672	$2.77
Sentinel	$17,262	49.9%	2,340	$3.68
Unmetered Scattered Load	$21,182	71.1%	1,812	$8.31
Total	**$7,116,900**			

DETERMINATION OF VOLUMETRIC CHARGES

Variable Distribution 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 8-7 provides OPDC's calculations of its proposed variable distribution charges for the 2010 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

TABLE 8-7: Proposed Distribution Volumetric Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Variable Distribution Charge before TX Allowance
Residential	$3,628,316	$2,109,752	$1,518,563	108,676,163	kWh	$0.0140
GS <50 kW	$1,341,448	$578,206	$763,242	48,230,452	kWh	$0.0158
GS>=50 kW	$1,925,281	$706,933	$1,218,348	397,192	kW	$3.0674
Street Light	$183,411	$118,201	$65,209	7,098	kW	$9.1870
Sentinel	$17,262	$8,611	$8,651	896	kW	$9.6555
Unmetered Scattered Load	$21,182	$15,058	$6,124	822,688	kWh	$0.0074
Total	**$7,116,900**	**$3,536,762**	**$3,580,138**			

Proposed Adjustment for Transformer Allowance:

Currently, OPDC provides a Transformer Allowance to those customers that own their transformation facilities. OPDC 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. 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.

The amount of Transformer Allowance expected to be provided to those General Service > 50 kW customers that own their transformers has been included in the volumetric charge for this class. This means the General Service > 50 kW volumetric charge of $3.0674 per kW will increase by $0.3585 per kW to a total of $3.4259 per kW to recover the amount of the Transformer Allowance spread over all kWs in the General Service > 50.

Recovery of Low Voltage Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $185,000 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. The amount of forecasted cost of LV in 2010 is based on OPDC's estimate of what it will be charged by Hydro One for that year.

The calculation to recover the 2010 LV amount is outlined in Table 8-8:

Table 8-8: Low Voltage Charges - Determination of Rates

	Retail TX Connection Rates		Billing Determinants		Allocation of Low Voltage Charges			Low Voltage Charge Rates		
Customer Class	Per kWh	per kW	Calculated kWh	Calculated kW	Retail Tx Con Revenue - Basis for Allocation	Allocation Percentages	Allocated $	Volumetric Rate Type	Low Voltage Rates/kWh	Low Voltage Rates/ kW
Residential	$0.0035		108,676,163		$380,367	35.90%	$66,407	kWh	$0.0006	
GS <50 kW	$0.0032		48,230,452		$154,337	14.57%	$26,945	kWh	$0.0006	
GS>=50 kW		$1.2955	150,956,406	397,192	$514,562	48.56%	$89,836	kW		$0.2262
Street Light		$0.9659	2,560,651	7,098	$6,856	0.65%	$1,197	kW		$0.1686
Sentinel		$0.9862	324,773	896	$884	0.08%	$154	kW		$0.1722
Unmetered Scattered Lo	$0.0032		822,688		$2,633	0.25%	$460	kWh	$0.0006	
TOTALS			**311,571,133**	**405,186**	**$1,059,638**	**100.00%**	**$185,000**			

RETAIL TRANSMISSION SERVICE RATES

Table 8-9 summarizes wholesale network and connection costs and retail billings for the year 2007 and 2008. Table 8-10 provides an analysis of variances between costs and revenues. Graph 8-1 displays month end variance balances for 2007 and 2008. As can be seen by both the tables and graphs there is no significant trend that must be reversed and OPDC does not propose to adjust RTSRs at this time.

Table 8-9: Wholesale Network and Connection Costs and Retail Billings for 2007 and 2008

Retail Transmission Network Variance G/L 1584	Costs	Retail Billing	Carrying Charges	Balance
2007 Opening Balance				($588,787)
2007	$1,378,124	($1,305,418)	($26,103)	($542,184)
2008	$1,062,809	($1,136,961)	($20,105)	($636,441)
2009 Jan to Jun (billed basis)	$400,863	($435,324)	($4,788)	($675,690)
TOTALS	**$2,841,796**	**($2,877,703)**	**($50,996)**	**($675,690)**

Retail Transmission Connection Variance G/L 1586	Costs	Retail Billing	Carrying Charges	Balance
2007 Opening Balance				($561,934)
2007	$1,144,097	($1,103,492)	($25,445)	($546,774)
2008	$955,623	($1,047,464)	($20,617)	($659,232)
2009 Jan to Jun (billed basis)	$374,180	($420,810)	($6,823)	($712,685)
TOTALS	**$2,473,900**	**($2,571,766)**	**($52,885)**	**($712,685)**

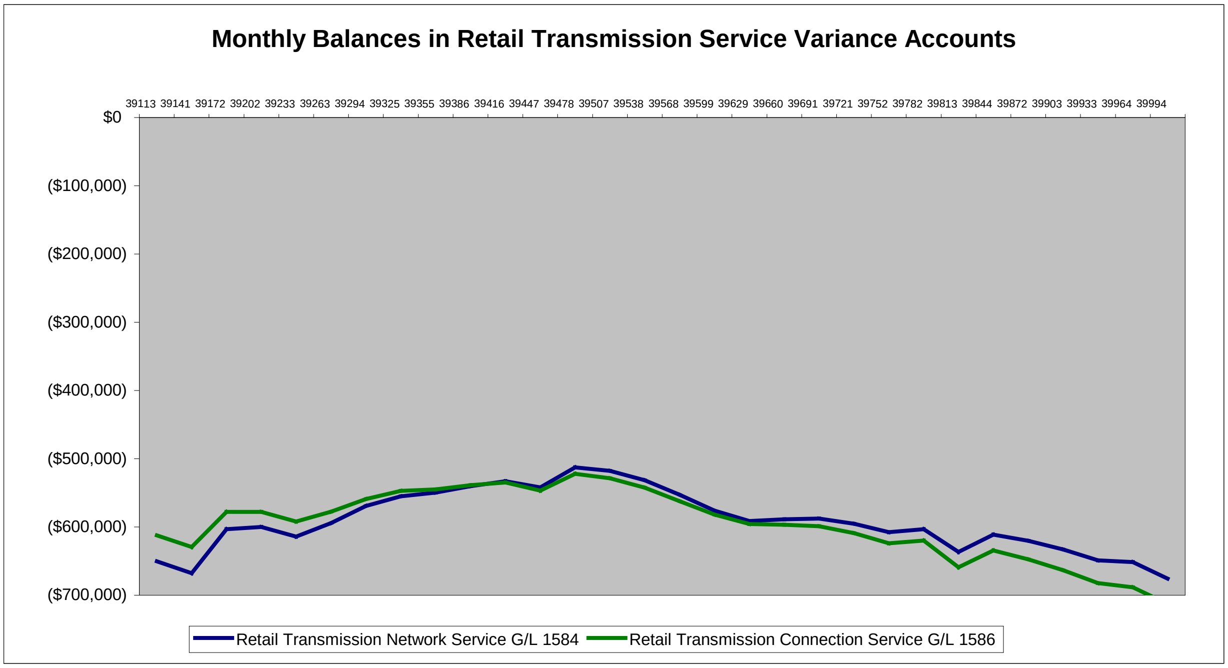
Table 8-10: Variances Between Costs and Revenues and Trends for RTSRs

RETAIL TRANSMISSION NETWORK COSTS AND RETAIL BILLINGS						
Date	Costs G/L 4714		Revenue G/L 4066		Month Variance	Variance as % of costs
	Rate	Amount	Rate Order	Amount		
Jan-07	$2.52	$114,612	May 2006 rates (no change May 2007)	($123,841)	**($9,229)**	**-8.1%**
Feb-07	$2.52	$121,310		($128,764)	**($7,454)**	**-6.1%**
Mar-07	$2.52	$122,646		($117,173)	**$5,473**	**4.5%**
Apr-07	$2.52	$94,326		($106,364)	**($12,038)**	**-12.8%**
May-07	$2.52	$115,413		($93,259)	**$22,154**	**19.2%**
Jun-07	$2.52	$129,480		($102,184)	**$27,296**	**21.1%**
Jul-07	$2.52	$121,640		($105,483)	**$16,157**	**13.3%**
Aug-07	$2.52	$117,409		($109,799)	**$7,610**	**6.5%**
Sep-07	$2.52	$113,153		($101,815)	**$11,338**	**10.0%**
Oct-07	$2.52	$109,524		($100,141)	**$9,383**	**8.6%**
Nov-07	$2.52	$125,912		($106,003)	**$19,909**	**15.8%**
Dec-07	$2.52	$124,609		($119,835)	**$4,774**	**3.8%**
Dec-07	ADJ UNBILLED			$9,243		
Dec-07	OTHER CREDITS	($31,910)				
		$1,378,124		**($1,305,418)**		
Jan-08	$2.52	$114,131		($117,239)	**($3,108)**	**-2.7%**
Feb-08	$2.52	$108,831		($120,749)	**($11,918)**	**-11.0%**
Mar-08	$2.52	$96,985		($116,816)	**($19,831)**	**-20.4%**
Apr-08	$2.52	$85,807		($107,326)	**($21,519)**	**-25.1%**
May-08	$2.01	$71,200	May 2008 rates	($84,528)	**($13,328)**	**-18.7%**
Jun-08	$2.01	$87,522		($83,323)	**$4,199**	**4.8%**
Jul-08	$2.01	$85,618		($83,115)	**$2,503**	**2.9%**
Aug-08	$2.01	$78,671		($84,711)	**($6,040)**	**-7.7%**
Sep-08	$2.01	$71,299		($82,357)	**($11,058)**	**-15.5%**
Oct-08	$2.01	$83,077		($77,178)	**$5,899**	**7.1%**
Nov-08	$2.01	$84,937		($87,684)	**($2,747)**	**-3.2%**
Dec-08	$2.01	$94,731		($97,167)	**($2,436)**	**-2.6%**
Dec-08	ADJ UNBILLED			$5,233		
		$1,062,809		**($1,136,961)**		
Jan-09	REV ADJ UNBILLED			$26,433		
Jan-09	$2.01	$96,179		($104,073)	**($7,894)**	**-8.2%**
Feb-09	$2.01	$87,694		($99,271)	**($11,577)**	**-13.2%**
Mar-09	$2.01	$74,463		($90,076)	**($15,613)**	**-21.0%**
Apr-09	$2.01	$82,623		($84,680)	**($2,057)**	**-2.5%**
May-09	$2.01	$59,904	May 2009 rates	($83,657)	**($23,753)**	**-39.7%**
Jun-09	$2.24					
		$400,863		**($435,324)**		

Table 8-10 (continued) : Variances Between Costs and Revenues and Trends for RTSRs

RETAIL TRANSMISSION CONNECTION COSTS AND RETAIL BILLINGS						
Date	Costs G/L 4714		Revenue G/L 4068		Month Variance	Variance as % of costs
	Rate	Amount	Rate Order	Amount		
Jan-07	$2.09	$95,055	May 2006 rates (no change May 2007)	($104,766)	**($9,711)**	**-10.2%**
Feb-07	$2.09	$100,611		($108,103)	**($7,492)**	**-7.4%**
Mar-07	$2.09	$101,718		($99,114)	**$2,604**	**2.6%**
Apr-07	$2.09	$78,231		($90,324)	**($12,093)**	**-15.5%**
May-07	$2.09	$95,720		($79,133)	**$16,587**	**17.3%**
Jun-07	$2.09	$107,386		($86,680)	**$20,706**	**19.3%**
Jul-07	$2.09	$102,843		($88,955)	**$13,888**	**13.5%**
Aug-07	$2.09	$97,375		($93,204)	**$4,171**	**4.3%**
Sep-07	$2.09	$93,845		($85,774)	**$8,071**	**8.6%**
Oct-07	$2.09	$90,836		($84,611)	**$6,225**	**6.9%**
Nov-07	$2.09	$104,427		($89,454)	**$14,973**	**14.3%**
Dec-07	$2.09	$103,332		($101,279)	**$2,053**	**2.0%**
Dec-07	ADJ UNBILLED			$7,906		
Dec-07	OTHER CREDITS	($27,282)				
		$1,144,097		**($1,103,492)**		
Jan-08	$2.09	$94,656		($99,104)	**($4,448)**	**-4.7%**
Feb-08	$2.09	$90,261		($102,074)	**($11,813)**	**-13.1%**
Mar-08	$2.09	$80,436		($98,746)	**($18,310)**	**-22.8%**
Apr-08	$2.09	$72,941		($90,728)	**($17,787)**	**-24.4%**
May-08	$1.88	$66,595	May 2008 rates	($78,645)	**($12,050)**	**-18.1%**
Jun-08	$1.88	$81,861		($81,213)	**$648**	**0.8%**
Jul-08	$1.88	$80,080		($80,843)	**($763)**	**-1.0%**
Aug-08	$1.88	$73,609		($82,229)	**($8,620)**	**-11.7%**
Sep-08	$1.88	$66,687		($80,023)	**($13,336)**	**-20.0%**
Oct-08	$1.88	$80,485		($75,099)	**$5,386**	**6.7%**
Nov-08	$1.88	$79,443		($85,180)	**($5,737)**	**-7.2%**
Dec-08	$1.88	$88,569		($94,582)	**($6,013)**	**-6.8%**
Dec-08	ADJ UNBILLED			$1,002		
		$955,623		**($1,047,464)**		
Jan-09	REV ADJ UNBILLED			$25,818		
Jan-09	$1.88	$89,958		($101,095)	**($11,137)**	**-12.4%**
Feb-09	$1.88	$82,023		($96,490)	**($14,467)**	**-17.6%**
Mar-09	$1.88	$69,652		($87,493)	**($17,841)**	**-25.6%**
Apr-09	$1.88	$77,279		($82,774)	**($5,495)**	**-7.1%**
May-09	$1.88	$55,268	May 2009 rates	($78,776)	**($23,508)**	**-42.5%**
Jun-09	$1.99					
		$374,180		**($420,810)**		

Graph 8-1: Variances Between Costs and Revenues for RTSRs



LOSS FACTOR CALCULATIONS

Embedded Status:

Orillia is embedded within Hydro One's transmission system and receives substantially all (approximately 94%) of its power requirements from the Orillia Transformer Station. Beginning in 2010, 100% of Orillia's power needs will be supplied by the Orillia TS.

Prior to 2010, approximately 6% of the City of Orillia's power has been supplied by OPDC's affiliate, the Orillia Power Generation Corporation at the Hourly Ontario Energy Price (HOEP). This power is produced by a 2.8 mW waterpower plant located near Matthiasville and supplied to Orillia via subtransmission lines to an OPDC substation located within Orillia.

OPDC is currently working with Hydro One to connect the Matthias subtransmission line directly into Hydro One's system near Washago and once connected, the City of Orillia will obtain 100% of its power needs from the Orillia Transformer station.

Distribution System Loss Factors:

OPDC distribution loss factors have remained reasonably consistent and quite low over the period 2002 to 2008 and are projected to do so over the next few years. OPDC works hard at maintaining its distribution system and performs load studies to ensure that losses are minimized. Table 8-11 outlines OPDC loss factor history for the period 2002 to 2008. As can be seen from the table, our three year average distribution loss factor has actually declined from 1.0342 (2002 to 2004 average) to 1.0336 (2006 to 2008 average).

Table 8-11: LOSS FACTOR CALCULATIONS 2002 to 2008

	Description	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual
DISTRIBUTION LOSS ADJUSTMENT FACTOR								
A	"Wholesale" kWh IESO plus Embedded Generation	*327,646,404*	*326,488,330*	*327,399,956*	*335,789,477*	*329,335,625*	*333,321,095*	*330,155,445*
B	"Wholesale" kWh for Large Use customer(s)							
C	Net "Wholesale" kWh (A)-(B)	327,646,404	326,488,330	327,399,956	335,789,477	329,335,625	333,321,095	330,155,445
D	"Retail" kWh (Distributor)	317,673,033	314,305,835	317,099,431	323,017,340	320,376,795	321,106,485	319,007,970
E	"Retail" kWh for Large Use Customer(s)							
F	Net "Retail" kWh (D)-(E)	317,673,033	314,305,835	317,099,431	323,017,340	320,376,795	321,106,485	319,007,970
G	Loss Factor [(C)/(F)]	1.0314	1.0388	1.0325	1.0395	1.0280	1.0380	1.0349
H	**Distribution Loss Adjustment Factor**	**Average 2002-2004**		**1.0342**		**Average 2006-2008**		**1.0336**
SUPPLY LOSS ADJUSTMENT FACTOR								
I	"Wholesale" kWh with Losses	*327,858,855*	*326,758,737*	*329,583,057*	*346,922,941*	*339,836,662*	*340,350,915*	*337,342,212*
J	"Wholesale" kWh without Losses	*327,646,404*	*326,488,330*	*327,399,956*	*335,789,477*	*329,335,625*	*333,321,095*	*330,155,445*
K	Supply Facility Loss Factor	1.0006	1.0008	1.0067	1.0332	1.0319	1.0211	1.0218
L	**Supply Loss Adjustment Factor**	**Average 2002-2004**		**1.0027**		**Average 2006-2008**		**1.0249**
TOTAL LOSS ADJUSTMENT FACTOR								
M	**Total Loss Adjustment Factor (H) + (L)**	**Average 2002-2004**		**1.0370**		**Average 2006-2008**		**1.0593**
SUMMARY OF LOSS FACTORS								
H	Distribution Loss Factor - Secondary Metered Customer < 5,000kW			**1.0342**				**1.0336**
N	Distribution Loss Factor - Primary Metered Customer < 5,000kW (H) x 0.99			**1.0239**				**1.0233**
M	Total Loss Factor - Secondary Metered Customer < 5,000kW			**1.0370**				**1.0593**
O	Total Loss Factor - Primary Metered Customer < 5,000kW (L) x (N)			**1.0266**				**1.0487**

Supply Facilities Loss Factor:

In November 2004, meters were upgraded on our M1, M7 and M8 feeders in order to comply with market regulations. Due to the change in meter setup, Hydro One began charging OPDC with transmission losses at Hydro One's standard rate of 3.4%. While we were able to mitigate this rate somewhat, due to ensuring that as many feeders as possible were dedicated to supply of Orillia only, our supply facilities loss factor was still increased substantially causing a significant increase in the total loss factor.

As can be seen from Table 8-11, the three year average of the supply facilities loss factor has increased from 1.0027 (2002 to 2004 average) to 1.0249 (2006 to 2008 average).

Total Loss Factor:

The total loss factor charged to Orillia customers can be derived by multiplying the distribution system loss factor by the supply facilities loss factor. Since the 2006 EDR, Orillia has been using a total loss factor of 3.7% (1.0346 x 1.0027) which is the average of the total losses experienced in the period 2002 to 2004.

As summarized in Table 8-12, Orillia Power Distribution proposes to adjust this total loss factor to 5.93% at the same time as the other changes in proposed distribution rates are put into effect on May 1, 2010. This represents the average loss rate experienced for the period 2006 to 2008 (1.0336 x 1.0249) and it is expected that it will approximate the rate experienced going forward through 2010 and beyond.

Table 8-12: LOSS FACTORS EXISTING AND PROPOSED FOR TEST YEAR

Loss Factors	2009 Current Approved	2010 Proposed
Supply Facilities Loss Factor	1.0027	1.0249
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0342	1.0336
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0239	1.0233
Total Loss Factor - Secondary Metered Customer < 5,000 kW	**1.0370**	**1.0593**
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0267	1.0487

CURRENT APPROVED RATE CLASSES

The following summarizes OPDC's approved existing rate classes;

Residential:

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50kW:

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service 50 to 4,999 kW:

This classification refers to a non-residential account whose monthly average peak demand is greater than or equal to, or is forecast to be greater than or equal to, 50 kW but less than 5,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

Unmetered Scattered Load:

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load.

Sentinel Lighting:

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting:

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

CURRENT APPROVED DISTRIBUTION RATES

A copy of OPDC's latest Rates Decision and Order of the Ontario Energy Board is attached as Appendix 8-A. Pages 10 to 13 of the Rate Order outlines OPDC's Tariff of Rates and Charges Effective May 1, 2009.

REVENUES AT EXISTING RATES

Table 8-13 calculates core distribution revenues (excludes smart meter funding adder and low voltage adder) by rate class using test year billing determinants and OPDC's current approved rates as outlined in the rate order in Appendix 8- A.

Table 8-13: 2010 Test Year Billing Determinants Applied to Current Approved Core Distribution Rates

	Load Forecast - Billing Determinants For 2010				
Class	**kWh**	**kw**	**Transformer Discount kw**	**Annualized Customers (Average)**	**Annualized Connections (Average)**
Residential	108,676,163			136,908	
GS <50 kW	48,230,452			16,260	
GS>=50 kW	150,956,406	397,192	237,300	1,884	
Street Light	2,560,651	7,098			42,672
Sentinel	324,773	896			2,340
Unmetered Scattered Lo	822,688				1,812
Transformer Discount					
TOTALS	**311,571,133**	**405,186**	**237,300**	**155,052**	**46,824**

	Core Distribution Rates - Current Approved				
Class	**Connection**	**Customer**	**kW**	**kWh**	**2010 Revenues Based on May 1, 2009 Rates**
Residential		$13.3400		$0.0121	**$3,141,334**
GS <50 kW		$30.7900		$0.0137	**$1,161,403**
GS>=50 kW		$338.0400	$3.1219		**$1,734,481**
Street Light	$1.0600		$3.5300		**$70,288**
Sentinel	$3.1900		$8.3493		**$14,946**
Unmetered Scattered Lo	$15.3900			$0.0138	**$39,240**
Transformer Discount			($0.6000)		
TOTALS					**$6,161,692**

PROPOSED RATE CLASSES

OPDC is not requesting any changes to the existing rate classes as outlined in Exhibit 8 Tab 5 Schedule 1.

PROPOSED DISTRIBUTION RATES

Table 8-14 lists ONLY electricity distribution rates and loss factors that OPDC proposes to change effective May 1, 2010. Distribution rates not changing are not listed in Table 8-14. Rates based on the calculations in Exhibit 8 include adjustments for the recovery of transformer allowance, low voltage charges and the smart meter funding adder. The regulatory asset riders resulting from the clearance of deferral and variance accounts shown in Table 9-4 are also shown here for completeness. No changes to any other specific or other service charges are being proposed in this application.

OPDC is requesting continuation of the currently approved smart meter adder of $1.00 per metered customer. OPDC will complete a separate application for a rate rider once the smart meter implementation is complete and capital and operating costs are established.

Table 8-14: Schedule of Distribution Rates and Loss Factors Proposed to Change

Description	Metric	Approved Schedule of Rates and Charges May 1, 2009	Proposed Schedule of Rates and Charges May 1, 2010
RESIDENTIAL			
Service Charge	$	14.34	15.41
Distribution Volumetric Rate	$/kWh	0.0128	0.0140
Regulatory Asset Rider (One Year)	$/kWh		(0.0013)
GENERAL SERVICE LESS THAN 50 KW			
Service Charge	$	31.79	35.56
Distribution Volumetric Rate	$/kWh	0.0144	0.0158
Regulatory Asset Rider (One Year)	$/kWh		(0.0011)
GENERAL SERVICE 50 to 4,999 KW			
Service Charge	$	339.04	375.23
Distribution Volumetric Rate	$/kW	3.4023	3.4259
Regulatory Asset Rider (One Year)	$/kW		(0.5841)
UNMETERED SCATTERED LOAD			
Service Charge	$	15.39	8.31
Distribution Volumetric Rate	$/kWh	0.0144	0.0074
Regulatory Asset Rider (One Year)	$/kWh		(0.0001)
SENTINEL LIGHTING			
Service Charge	$	3.19	3.68
Distribution Volumetric Rate	$/kW	8.5424	9.6553
Regulatory Asset Rider (One Year)	$/kW		(0.5318)
STREET LIGHTING			
Service Charge	$	1.06	2.77
Distribution Volumetric Rate	$/kW	3.7225	9.1870
Regulatory Asset Rider (One Year)	$/kW		(0.2590)
LOSS FACTORS			
Total Loss Factor - Secondary Metered Customer < 5,000 kW		1.0370	1.0593
Total Loss Factor - Primary Metered Customer < 5,000 kW		1.0267	1.0487

Table 8-15 breaks out OPDC's proposed 2010 core electricity distribution rates from smart meter adders and low voltage charges based on the foregoing calculations in Exhibit 8 Tab 2 and includes adjustments for the recovery of transformer allowance.

Table 8-15: Components of Proposed Distribution Rates Effective May 1, 2010

Rate Classification	Proposed Monthly Service Charge Excl Smart Meter Adder	Proposed Monthly Funding Adder for Smart Meters	Proposed Monthly Service Charge Including Smart Meter Adder	Unit of Measure	Proposed Volumetric Distribution Charge excluding LV Charge	Low Voltage (LV) Charge	Proposed Volumetric Distribution Charge including LV Charge
Residential	**$15.41**	$1.00	**$16.41**	kWh	**$0.0140**	$0.0006	**$0.0146**
GS <50 kW	**$35.56**	$1.00	**$36.56**	kWh	**$0.0158**	$0.0006	**$0.0164**
GS>=50 kW	**$375.23**	$1.00	**$376.23**	kW	**$3.4259**	$0.2262	**$3.6521**
Street Light	**$2.77**		**$2.77**	kW	**$9.1870**	$0.1686	**$9.3556**
Sentinel	**$3.68**		**$3.68**	kW	**$9.6555**	$0.1722	**$9.8277**
Unmetered Scattered Load	**$8.31**		**$8.31**	kWh	**$0.0074**	$0.0006	**$0.0080**
Transformer Discount				kW	**($0.60)**		**($0.60)**

For greater certainty, Table 8-15 does not list the regulatory asset riders indicated in Table 8-14.

Table 8-16 calculates core distribution revenues (excludes smart meter funding adder and low voltage adder) by rate class using test year billing determinants and OPDC's proposed core rates as outlined in Table 8-15 required to achieve the total base revenue required.

Table 8-16: 2010 Test Year Billing Determinants Applied to Proposed Core Distribution Rates

	Load Forecast - Billing Determinants For 2010				
Class	kWh	kw	Transformer Discount kw	Annualized Customers (Average)	Annualized Connections (Average)
Residential	108,676,163			136,908	
GS <50 kW	48,230,452			16,260	
GS>=50 kW	150,956,406	397,192	237,300	1,884	
Street Light	2,560,651	7,098			42,672
Sentinel	324,773	896			2,340
Unmetered Scatt	822,688				1,812
Transformer Disc					
TOTALS	**311,571,133**	**405,186**	**237,300**	**155,052**	**46,824**

	Core Distribution Rates				
Class	Connection	Customer	kW	kWh	2010 Revenues Based on Applied For Rates
Residential		$15.4100		$0.0140	**$3,628,315**
GS <50 kW		$35.5600		$0.0158	**$1,341,448**
GS>=50 kW		$375.2300	$3.4259		**$1,925,281**
Street Light	$2.7700		$9.1870		**$183,411**
Sentinel	$3.6800		$9.6553		**$17,262**
Unmetered Scatt	$8.3100			$0.0074	**$21,182**
Transformer Disc			($0.6000)		
TOTALS					**$7,116,900**

Table 8-17 lists **ALL** rates and charges proposed to be effective May 1, 2010 including loss factors, specific service and other charges.

Table 8-17 Part 1: SCHEDULE OF PROPOSED RATES AND CHARGES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
RESIDENTIAL		
Service Charge	$	15.41
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0140
Low Voltage Cost Recovery	$/kWh	0.0006
Regulatory Asset Rider (One Year)	$/kWh	(0.0013)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035
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	$	35.56
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0158
Low Voltage Cost Recovery	$/kWh	0.0006
Regulatory Asset Rider (One Year)	$/kWh	(0.0011)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
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	$	375.23
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	3.4259
Low Voltage Cost Recovery	$/kW	0.2262
Regulatory Asset Rider (One Year)	$/kW	(0.5841)
Retail Transmission Rate – Network Service Rate	$/kW	1.4236
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2955
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
STANDBY POWER		
Distribution Volumetric Rate - $ per kW of nameplate capacity (per month)	$/kW	1.0110

Table 8-17 Part 1 (continued): SCHEDULE OF PROPOSED RATES AND CHARGES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
UNMETERED SCATTERED LOAD		
Service Charge (per connection)	$	8.31
Distribution Volumetric Rate	$/kWh	0.0074
Low Voltage Cost Recovery	$/kWh	0.0006
Regulatory Asset Rider (One Year)	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
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)	$	3.68
Distribution Volumetric Rate	$/kW	9.6553
Low Voltage Cost Recovery	$/kW	0.1722
Regulatory Asset Rider (One Year)	$/kW	(0.5318)
Retail Transmission Rate – Network Service Rate	$/kW	1.0541
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9862
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)	$	2.77
Distribution Volumetric Rate	$/kW	9.1870
Low Voltage Cost Recovery	$/kW	0.1686
Regulatory Asset Rider (One Year)	$/kW	(0.2590)
Retail Transmission Rate – Network Service Rate	$/kW	1.0487
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9659
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Table 8-17 Part 2: SCHEDULE OF PROPOSED SPECIFIC SERVICE CHARGES AND ALLOWANCES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
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
Other		
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1000.00
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 -transformer losses - applied to measured demand and ene and energy	%	(1.00)

Table 8-17 Part 3: SCHEDULE OF PROPOSED RETAIL SERVICE CHARGES

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
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

Table 8-17 Part 4: SCHEDULE OF PROPOSED LOSS FACTORS

Description	Metric	Proposed Schedule of Rates and Charges Effective May 1, 2010
LOSS FACTORS		
Total Loss Factor - Secondary Metered Customer < 5,000 kW		1.0593
Total Loss Factor - Secondary Metered Customer > 5,000 kW		N/A
Total Loss Factor - Primary Metered Customer < 5,000 kW		1.0487
Total Loss Factor - Primary Metered Customer > 5,000 kW		N/A

CUSTOMER BILL IMPACTS FROM PROPOSED CHANGES TO RATES

Customer rate impacts are assessed on the basis of moving to the proposed distribution rates calculated for each rate class at various levels of consumption. Table 8-18 summarizes customer total bill impacts by class by levels of consumption. Appendix 8-B to this Exhibit presents detailed calculations for Table 8-18.

Impacts are shown using the applicable current approved rates and the proposed 2010 distribution rates, including a Rate Rider for the repayment of the balances in the variance accounts as calculated in Exhibit 9. OPDC is proposing to leave the funding adder for smart meters unchanged from May 1, 2009.

RATE MITIGATION IMPLICATIONS

OPDC submits that the bill impacts of its proposed 2010 electricity distribution rates are reasonable and do not require rate mitigation.

For the Street Light rate class the bill impacts are above 10% resulting from the implementation of the recent cost allocation study. OPDC has proposed to move this customer class significantly closer to the OEB's target range of acceptable Revenue to Cost ratio. As a result, it is expected this class will experience significantly higher increases than the other customer classes.

Table 8-18: SUMMARY Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

RESIDENTIAL

VOLUMES	Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
100	$15.62	$17.74	$2.12	$23.48	$25.73	$2.25	13.6%	9.0%	9.6%
250	$17.54	$19.73	$2.19	$37.10	$39.73	$2.63	12.5%	5.9%	7.1%
500	$20.74	$23.06	$2.32	$59.93	$63.04	$3.11	11.2%	3.9%	5.2%
800	**$24.58**	**$27.05**	**$2.47**	**$89.34**	**$93.16**	**$3.82**	**10.0%**	**2.8%**	**4.3%**
1,000	$27.14	$29.71	$2.57	$109.39	$113.71	$4.32	9.5%	2.3%	3.9%
1,500	$33.54	$36.36	$2.82	$159.66	$165.11	$5.45	8.4%	1.8%	3.4%
2,000	$39.94	$43.02	$3.08	$209.84	$216.51	$6.67	7.7%	1.5%	3.2%

GENERAL SERVICE LESS THAN 50 KW

VOLUMES	Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
1,000	$46.19	$51.92	$5.73	$126.26	$133.72	$7.46	12.4%	4.5%	5.9%
2,000	**$60.59**	**$67.29**	**$6.70**	**$227.48**	**$237.73**	**$10.25**	**11.1%**	**2.9%**	**4.5%**
3,000	$74.99	$82.65	$7.66	$328.72	$341.67	$12.95	10.2%	2.3%	3.9%
5,000	$103.79	$113.38	$9.59	$531.15	$549.59	$18.44	9.2%	1.8%	3.5%
10,000	$175.79	$190.21	$14.42	$1,037.27	$1,069.31	$32.04	8.2%	1.4%	3.1%
15,000	$247.79	$267.02	$19.23	$1,543.39	$1,589.09	$45.70	7.8%	1.2%	3.0%
20,000	$319.79	$343.85	$24.06	$2,049.50	$2,108.80	$59.30	7.5%	1.2%	2.9%

GENERAL SERVICE 50 KW AND OVER

VOLUMES			Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	Load Factor	Kw	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
24,000	56%	60	$543.18	$560.30	$17.12	$2,354.54	$2,404.58	$50.04	3.15%	0.73%	2.13%
40,000	56%	100	$679.27	$683.03	$3.76	$3,698.20	$3,756.82	$58.62	0.55%	0.10%	1.59%
200,000	56%	500	$2,040.19	$1,910.20	($129.99)	$17,134.84	$17,279.14	$144.30	-6.37%	-0.76%	0.84%
400,000	56%	1,000	$3,741.34	$3,444.18	($297.16)	$33,930.64	$34,182.06	$251.42	-7.94%	-0.88%	0.74%
1,000,000	56%	2,500	$8,844.79	$8,046.10	($798.69)	$84,318.04	$84,890.80	$572.76	-9.03%	-0.95%	0.68%
1,250,000	56%	3,100	$10,886.17	$9,886.88	($999.29)	$105,159.76	$105,874.78	$715.02	-9.18%	-0.95%	0.68%
1,600,000	56%	4,000	$13,948.24	$12,648.04	($1,300.20)	$134,705.44	$135,599.56	$894.12	-9.32%	-0.97%	0.66%

STREET LIGHTING

VOLUMES			Distribution Portion $$$			Total Bill $$$			Perentage Changes		
kWh	Kw	Connectio ns	2009	2010	Change	2009	2010	Change	Distribution 2009 to 2010	Distribution vs Total 2009	Total Bill 2009 to 2010
193,000	520	3,200	$5,327.70	$13,594.23	$8,266.53	$19,629.67	$28,160.89	$8,531.22	155.2%	42.1%	43.5%
205,000	560	3,400	$5,688.60	$14,512.09	$8,823.49	$20,895.25	$29,999.92	$9,104.67	155.1%	42.2%	43.6%
217,000	**590**	**3,600**	**$6,012.28**	**$15,338.99**	**$9,326.71**	**$22,103.48**	**$31,727.78**	**$9,624.30**	**155.1%**	**42.2%**	**43.5%**
229,000	620	3,800	$6,335.95	$16,165.89	$9,829.94	$23,311.69	$33,455.71	$10,144.02	155.1%	42.2%	43.5%
241,000	660	4,000	$6,696.85	$17,083.75	$10,386.90	$24,577.28	$35,294.68	$10,717.40	155.1%	42.3%	43.6%

APPENDIX 8–A

The next 13 pages are the OPDC's latest Rates Decision and Order of the Ontario Energy Board. Pages 10 to 13 outline OPDC's Tariff of Rates and Charges Effective May 1, 2009.

EB-2008-0239

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Orillia Power Distribution Corp. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

Introduction

Orillia Power Distribution Corp. ("Orillia Power") is a licensed distributor of electricity providing service to consumers within its licensed service area. Orillia Power filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2009.

Orillia Power is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, Orillia Power is one of the electricity distributors to have its rates adjusted for 2009 on the basis of the

2nd Generation Incentive Rate Mechanism ("IRM") process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2009 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process.

Notice of Orillia Power's rate application was given through newspaper publication in Orillia Power's service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. There were no intervention requests and no comments were received. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Orillia Power's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for Orillia Power, the Board has applied the policies described in the Report.

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2008 data published by Statistics Canada, the Board has established the price escalator to be 2.3%. The resulting price cap index adjustment is therefore 1.3%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. A change in the federal income tax rate effective January 1, 2009 was incorporated into the rate model and reflected in distribution rates.

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic Outlook and Fiscal Review (the "Fiscal Review"). The enabling legislation received Royal Assent on May 14, 2008. Included in this Fiscal Review were changes to the Ontario capital tax provisions[1], and an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2007.

The Federal Budget enacted on February 3, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009, and a change in the capital cost allowance (CCA) applicable to certain computer equipment and related system software (CCA class 50) acquired between January 27, 2009 and February 2011.

The Board has considered these fiscal changes and determined that the rate model will be adjusted to reflect the increase in the provincial and federal small business income limit for affected distributors, and the changes in the Ontario capital tax provisions. The Board is of the view that these changes when combined could be material, and should be passed through to ratepayers. With regard to the change in the CCA, the Board notes that this change would be captured in the revenue requirement calculation as it relates to smart meters when a distributor applies for cost recovery for the applicable investment period. For other computer equipment and related system software in class 50, the Board concludes that this adjustment is not required since it does not appear to be material.

[1] The Ontario capital tax rate decreased from 0.285% to 0.225% effective January 1, 2007. The Ontario capital tax deduction also increased from $10 million to $12.5 million effective January 1, 2007, and from $12.5 million to $15 million effective January 1, 2008.

The price cap index adjustment does not apply to the following components of distribution rates:

- Rate Riders;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Retail Service Charges;
- Loss Factors; and
- Smart Meter Funding Adder.

Rural or Remote Electricity Rate Protection Adjustment

In accordance with Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection (“RRRP”) (made under the *Ontario Energy Board Act, 1998*) the Board issued a Decision on December 17, 2008 setting out the amount to be charged by the Independent Electricity System Operator (“IESO”) with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

In a letter dated December 17, 2008 the Board directed distributors that had a rate application before the Board to file a request with the Board that the RRRP charge in their tariff sheet be revised to 0.13 cent per kilowatt-hour effective May 1, 2009.

Orillia Power complied with this directive. The rate model was adjusted to reflect the new RRRP charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery (“Smart Meter Guideline”) which sets out the Board’s filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law.

Orillia Power reports that it is authorized to conduct smart meter activities because it has procured smart meters pursuant to and in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc.

Orillia Power requested the standard smart meter funding adder of $1.00 per metered customer per month, which is intended to provide funding in the case where a distributor may be in the early stages of planning and may not yet have sufficient cost information to request a utility-specific funding adder. The Board approves the funding adder of $1.00 per metered customer per month as proposed by Orillia Power. This new funding adder is reflected in the Tariff of Rates and Charges that is appended to this Decision and Order. Orillia Power’s variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.00 per metered customer per month is intended to provide funding for Orillia Power’s smart metering activities in the 2009 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Orillia Power applies for the recovery of these costs.

Retail Transmission Service Rates

On October 22, 2008 the Board issued a Guideline for *Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") which provides electricity distributors with instructions on the evidence needed, and the process to be used, to adjust Retail Transmission Service Rates ("RTSRs") to reflect changes in the Ontario Uniform Transmission Rates ("UTRs").

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new UTRs for Ontario transmitters, effective January 1, 2009. The Board approved an increase of 11.3% to the wholesale transmission network rate, an increase of 18.6% to the wholesale transmission line connection rate, and an increase of 0.6% to the wholesale transformation connection rate. The combined change in the wholesale transmission and transformation connection rates is an increase of about 5%.

Electricity distributors are charged the UTRs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral accounts are also used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e., deferral accounts 1584 and 1586).

In the RTSR Guideline the Board directed all electricity distributors to propose an adjustment to their RTSRs to reflect the new UTRs for Ontario transmitters effective January 1, 2009. The objective of resetting the rates was to minimize the prospective balances in deferral accounts 1584 and 1586.

Orillia Power proposed to increase its RTSR – Network Service Rates by 11% and to increase its RTSR – Line and Transformation Connection Service Rates by 5%. The Board finds that this approach is reasonable and therefore approves these adjustments.

The Board is providing Orillia Power with a rate model (spreadsheet) and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2008 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

Orillia Power's new distribution rates will be effective May 1, 2009. The Board orders that:

1. Orillia Power shall review the draft Tariff of Rates and Charges set out in Appendix A. Orillia Power shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information, within seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by Orillia Power to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

2. The draft Tariff of Rates and Charges set out in Appendix A of this Order will become final, effective May 1, 2009, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2009.

3. The Tariff of Rates and Charges set out in Appendix A of this Order shall supersede all previous distribution rate schedules approved by the Board for Orillia Power and is final in all respects.

4. Orillia Power shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

If the Board receives a submission by Orillia Power to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of Orillia Power and will issue a final Tariff of Rates and Charges.

DATED at Toronto, March 10, 2009

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix "A"

To Decision and Order

EB-2008-0239

March 10, 2009

Orillia Power Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0239

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Orillia Power Distribution Corporation has discontinued the distinction within this classification based on the type of meter at the customer's premises.

Standby Power
This classification applies to an account with load displacement facilities that contracts with the distributor to provide emergency standby power when its load displacement facilities are not in operation. The level of the billing demand will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation such as name-plate rating of the load displacement facility.

Unmetered Scattered Load
This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Orillia Power Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0239

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.34
Distribution Volumetric Rate	$/kWh	0.0128
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035
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	$	31.79
Distribution Volumetric Rate	$/kWh	0.0144
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
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	$	339.04
Distribution Volumetric Rate	$/kW	3.4023
Retail Transmission Rate – Network Service Rate	$/kW	1.4236
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2955
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Standby Power – APPROVED ON AN INTERIM BASIS

Distribution Volumetric Rate – $/kW of contracted amount	$/kW	1.0110

Unmetered Scattered Load

Service Charge (per connection)	$	15.39
Distribution Volumetric Rate	$/kWh	0.0144
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0032
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)	$	3.19
Distribution Volumetric Rate	$/kW	8.5424
Retail Transmission Rate – Network Service Rate	$/kW	1.0541
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9862
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Orillia Power Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0239

Street Lighting

Service Charge (per connection)	$	1.06
Distribution Volumetric Rate	$/kW	3.7225
Retail Transmission Rate – Network Service Rate	$/kW	1.0487
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9659
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
Easement Letter	$	15.00
Income tax letter	$	15.00
Account History	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charges for non payment of account - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charges for non payment of account - At Meter After Regular Hours	$	185.00
Disconnect/Reconnect Charges for non payment of account - At Pole During Regular Hours	$	185.00
Disconnect/Reconnect Charges for non payment of account – At Pole After Regular Hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
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)

Orillia Power Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0239

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	1.0370
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0267
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

APPENDIX 8-B

The next 15 pages outline detailed calculations of bill impacts for OPDC's major classes of customers.

RESIDENTIAL Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
100 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$13.34			$15.41	$2.07	15.52%	8.82%
Distribution (kWh)	100	$0.0128	$1.28	100	$0.0146	$1.46	$0.18	14.06%	0.77%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	100			100	($0.0013)	($0.13)	($0.13)		-0.55%
Distribution			**$15.62**			**$17.74**	**$2.12**	**13.57%**	**9.03%**
RTSR Network (kWh)	104	0.0038	$0.40	106	0.0038	$0.40			
RTSR Connection (kWh)	104	0.0035	$0.36	106	0.0035	$0.37	$0.01	2.78%	0.04%
Delivery (includes Distribution)			**$16.38**			**$18.51**	**$2.13**	**13.00%**	**9.07%**
Cost of Power Commodity (kWh)	104	$0.0570	$5.93	106	$0.0570	$6.04	$0.11	1.85%	0.47%
Cost of Power Commodity (kWh)		0.0660			0.0660			#DIV/0!	
Wholesale Market Service (kWh)	104	0.0065	$0.68	106	0.0065	$0.69	$0.01	1.47%	0.04%
Debt retirement charge (kWh)	100	0.0049	$0.49	100	0.0049	$0.49			
Cost of Power / WMS / DRC			**$7.10**			**$7.22**	**$0.12**	**1.69%**	**0.51%**
Total Bill			**$23.48**			**$25.73**	**$2.25**	**9.58%**	**9.58%**

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
250 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$13.34			$15.41	$2.07	15.52%	5.58%
Distribution (kWh)	250	$0.0128	$3.20	250	$0.0146	$3.64	$0.44	13.75%	1.19%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	250			250	($0.0013)	($0.32)	($0.32)		-0.86%
Distribution			**$17.54**			**$19.73**	**$2.19**	**12.49%**	**5.90%**
RTSR Network (kWh)	259	0.0038	$0.98	265	0.0038	$1.01	$0.03	3.06%	0.08%
RTSR Connection (kWh)	259	0.0035	$0.91	265	0.0035	$0.93	$0.02	2.20%	0.05%
Delivery (includes Distribution)			**$19.43**			**$21.67**	**$2.24**	**11.53%**	**6.04%**
Cost of Power Commodity (kWh)	259	$0.0570	$14.76	265	$0.0570	$15.11	$0.35	2.37%	0.94%
Cost of Power Commodity (kWh)		0.0660			0.0660			#DIV/0!	
Wholesale Market Service (kWh)	259	0.0065	$1.68	265	0.0065	$1.72	$0.04	2.38%	0.11%
Debt retirement charge (kWh)	250	0.0049	$1.23	250	0.0049	$1.23			
Cost of Power / WMS / DRC			**$17.67**			**$18.06**	**$0.39**	**2.21%**	**1.05%**
Total Bill			**$37.10**			**$39.73**	**$2.63**	**7.09%**	**7.09%**

RESIDENTIAL Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
500	kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$13.34			$15.41	$2.07	15.52%	3.45%
Distribution (kWh)		500	$0.0128	$6.40	500	$0.0146	$7.29	$0.89	13.91%	1.49%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kWh)		500			500	($0.0013)	($0.64)	($0.64)		-1.07%
Distribution				**$20.74**			**$23.06**	**$2.32**	**11.19%**	**3.87%**
RTSR Network (kWh)		519	0.0038	$1.97	530	0.0038	$2.01	$0.04	2.03%	0.07%
RTSR Connection (kWh)		519	0.0035	$1.82	530	0.0035	$1.86	$0.04	2.20%	0.07%
Delivery (includes Distribution)				**$24.53**			**$26.93**	**$2.40**	**9.78%**	**4.00%**
Cost of Power Commodity (kWh)		519	$0.0570	$29.58	530	$0.0570	$30.21	$0.63	2.13%	1.05%
Cost of Power Commodity (kWh)			0.0660			0.0660			#DIV/0!	
Wholesale Market Service (kWh)		519	0.0065	$3.37	530	0.0065	$3.45	$0.08	2.37%	0.13%
Debt retirement charge (kWh)		500	0.0049	$2.45	500	0.0049	$2.45			
Cost of Power / WMS / DRC				**$35.40**			**$36.11**	**$0.71**	**2.01%**	**1.18%**
Total Bill				**$59.93**			**$63.04**	**$3.11**	**5.19%**	**5.19%**

Consumption		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
800	kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$13.34			$15.41	$2.07	15.52%	2.32%
Distribution (kWh)		800	$0.0128	$10.24	800	$0.0146	$11.66	$1.42	13.87%	1.59%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kWh)		800			800	($0.0013)	($1.02)	($1.02)		-1.14%
Distribution				**$24.58**			**$27.05**	**$2.47**	**10.05%**	**2.76%**
RTSR Network (kWh)		830	0.0038	$3.15	847	0.0038	$3.22	$0.07	2.22%	0.08%
RTSR Connection (kWh)		830	0.0035	$2.91	847	0.0035	$2.96	$0.05	1.72%	0.06%
Delivery (includes Distribution)				**$30.64**			**$33.23**	**$2.59**	**8.45%**	**2.90%**
Cost of Power Commodity (kWh)		600	$0.0570	$34.20	600	$0.0570	$34.20			
Cost of Power Commodity (kWh)		230	0.0660	$15.18	247	0.0660	$16.30	$1.12	7.38%	1.25%
Wholesale Market Service (kWh)		830	0.0065	$5.40	847	0.0065	$5.51	$0.11	2.04%	0.12%
Debt retirement charge (kWh)		800	0.0049	$3.92	800	0.0049	$3.92			
Cost of Power / WMS / DRC				**$58.70**			**$59.93**	**$1.23**	**2.10%**	**1.38%**
Total Bill				**$89.34**			**$93.16**	**$3.82**	**4.28%**	**4.28%**

RESIDENTIAL Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
1,000	kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$13.34			$15.41	$2.07	15.52%	1.89%
Distribution (kWh)		1,000	$0.0128	$12.80	1,000	$0.0146	$14.57	$1.77	13.83%	1.62%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kWh)		1,000			1,000	($0.0013)	($1.27)	($1.27)		-1.16%
Distribution				**$27.14**			**$29.71**	**$2.57**	**9.47%**	**2.35%**
RTSR Network (kWh)		1,037	0.0038	$3.94	1,059	0.0038	$4.02	$0.08	2.03%	0.07%
RTSR Connection (kWh)		1,037	0.0035	$3.63	1,059	0.0035	$3.71	$0.08	2.20%	0.07%
Delivery (includes Distribution)				**$34.71**			**$37.44**	**$2.73**	**7.87%**	**2.50%**
Cost of Power Commodity (kWh)		600	$0.0570	$34.20	600	$0.0570	$34.20			
Cost of Power Commodity (kWh)		437	0.0660	$28.84	459	0.0660	$30.29	$1.45	5.03%	1.33%
Wholesale Market Service (kWh)		1,037	0.0065	$6.74	1,059	0.0065	$6.88	$0.14	2.08%	0.13%
Debt retirement charge (kWh)		1,000	0.0049	$4.90	1,000	0.0049	$4.90			
Cost of Power / WMS / DRC				**$74.68**			**$76.27**	**$1.59**	**2.13%**	**1.45%**
Total Bill				**$109.39**			**$113.71**	**$4.32**	**3.95%**	**3.95%**

Consumption		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
1,500	kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$13.34			$15.41	$2.07	15.52%	1.30%
Distribution (kWh)		1,500	$0.0128	$19.20	1,500	$0.0146	$21.86	$2.66	13.85%	1.67%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kWh)		1,500			1,500	($0.0013)	($1.91)	($1.91)		-1.20%
Distribution				**$33.54**			**$36.36**	**$2.82**	**8.41%**	**1.77%**
RTSR Network (kWh)		1,556	0.0038	$5.91	1,589	0.0038	$6.04	$0.13	2.20%	0.08%
RTSR Connection (kWh)		1,556	0.0035	$5.45	1,589	0.0035	$5.56	$0.11	2.02%	0.07%
Delivery (includes Distribution)				**$44.90**			**$47.96**	**$3.06**	**6.82%**	**1.92%**
Cost of Power Commodity (kWh)		600	$0.0570	$34.20	600	$0.0570	$34.20			
Cost of Power Commodity (kWh)		956	0.0660	$63.10	989	0.0660	$65.27	$2.17	3.44%	1.36%
Wholesale Market Service (kWh)		1,556	0.0065	$10.11	1,589	0.0065	$10.33	$0.22	2.18%	0.14%
Debt retirement charge (kWh)		1,500	0.0049	$7.35	1,500	0.0049	$7.35			
Cost of Power / WMS / DRC				**$114.76**			**$117.15**	**$2.39**	**2.08%**	**1.50%**
Total Bill				**$159.66**			**$165.11**	**$5.45**	**3.41%**	**3.41%**

RESIDENTIAL Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
2,000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$13.34			$15.41	$2.07	15.52%	0.99%
Distribution (kWh)	2,000	$0.0128	$25.60	2,000	$0.0146	$29.15	$3.55	13.87%	1.69%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	2,000			2,000	($0.0013)	($2.54)	($2.54)		-1.21%
Distribution			**$39.94**			**$43.02**	**$3.08**	**7.71%**	**1.47%**
RTSR Network (kWh)	2,074	0.0038	$7.88	2,119	0.0038	$8.05	$0.17	2.16%	0.08%
RTSR Connection (kWh)	2,074	0.0035	$7.26	2,119	0.0035	$7.42	$0.16	2.20%	0.08%
Delivery (includes Distribution)			**$55.08**			**$58.49**	**$3.41**	**6.19%**	**1.63%**
Cost of Power Commodity (kWh)	600	$0.0570	$34.20	600	$0.0570	$34.20			
Cost of Power Commodity (kWh)	1,474	0.0660	$97.28	1,519	0.0660	$100.25	$2.97	3.05%	1.42%
Wholesale Market Service (kWh)	2,074	0.0065	$13.48	2,119	0.0065	$13.77	$0.29	2.15%	0.14%
Debt retirement charge (kWh)	2,000	0.0049	$9.80	2,000	0.0049	$9.80			
Cost of Power / WMS / DRC			**$154.76**			**$158.02**	**$3.26**	**2.11%**	**1.55%**
Total Bill			**$209.84**			**$216.51**	**$6.67**	**3.18%**	**3.18%**

GENERAL SERVICE LESS THAN 50 KW Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
1,000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$30.79			$35.56	$4.77	15.49%	3.78%
Distribution (kWh)	1,000	$0.0144	$14.40	1,000	$0.0164	$16.42	$2.02	14.03%	1.60%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	1,000			1,000	($0.0011)	($1.06)	($1.06)		-0.84%
Distribution			**$46.19**			**$51.92**	**$5.73**	**12.41%**	**4.54%**
RTSR Network (kWh)	1,037	0.0033	$3.42	1,059	0.0033	$3.49	$0.07	2.05%	0.06%
RTSR Connection (kWh)	1,037	0.0032	$3.32	1,059	0.0032	$3.39	$0.07	2.11%	0.06%
Delivery (includes Distribution)			**$52.93**			**$58.80**	**$5.87**	**11.09%**	**4.65%**
Cost of Power Commodity (kWh)	750	$0.0570	$42.75	750	$0.0570	$42.75			
Cost of Power Commodity (kWh)	287	0.0660	$18.94	309	0.0660	$20.39	$1.45	7.66%	1.15%
Wholesale Market Service (kWh)	1,037	0.0065	$6.74	1,059	0.0065	$6.88	$0.14	2.08%	0.11%
Debt retirement charge (kWh)	1,000	0.0049	$4.90	1,000	0.0049	$4.90			
Cost of Power / WMS / DRC			**$73.33**			**$74.92**	**$1.59**	**2.17%**	**1.26%**
Total Bill			**$126.26**			**$133.72**	**$7.46**	**5.91%**	**5.91%**

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
2,000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$30.79			$35.56	$4.77	15.49%	2.10%
Distribution (kWh)	2,000	$0.0144	$28.80	2,000	$0.0164	$32.85	$4.05	14.06%	1.78%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	2,000			2,000	($0.0011)	($2.12)	($2.12)		-0.93%
Distribution			**$60.59**			**$67.29**	**$6.70**	**11.06%**	**2.95%**
RTSR Network (kWh)	2,074	0.0033	$6.84	2,119	0.0033	$6.99	$0.15	2.19%	0.07%
RTSR Connection (kWh)	2,074	0.0032	$6.64	2,119	0.0032	$6.78	$0.14	2.11%	0.06%
Delivery (includes Distribution)			**$74.07**			**$81.06**	**$6.99**	**9.44%**	**3.07%**
Cost of Power Commodity (kWh)	750	$0.0570	$42.75	750	$0.0570	$42.75			
Cost of Power Commodity (kWh)	1,324	0.0660	$87.38	1,369	0.0660	$90.35	$2.97	3.40%	1.31%
Wholesale Market Service (kWh)	2,074	0.0065	$13.48	2,119	0.0065	$13.77	$0.29	2.15%	0.13%
Debt retirement charge (kWh)	2,000	0.0049	$9.80	2,000	0.0049	$9.80			
Cost of Power / WMS / DRC			**$153.41**			**$156.67**	**$3.26**	**2.13%**	**1.43%**
Total Bill			**$227.48**			**$237.73**	**$10.25**	**4.51%**	**4.51%**

GENERAL SERVICE LESS THAN 50 KW Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
3,000 kWh	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**Rate Change Impact $**	**Change %**	**As a % of 2009 Total Bill**
Monthly Service Charge			$30.79			$35.56	$4.77	15.49%	1.45%
Distribution (kWh)	3,000	$0.0144	$43.20	3,000	$0.0164	$49.27	$6.07	14.05%	1.85%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	3,000			3,000	($0.0011)	($3.18)	($3.18)		-0.97%
Distribution			**$74.99**			**$82.65**	**$7.66**	**10.21%**	**2.33%**
RTSR Network (kWh)	3,111	0.0033	$10.27	3,178	0.0033	$10.49	$0.22	2.14%	0.07%
RTSR Connection (kWh)	3,111	0.0032	$9.96	3,178	0.0032	$10.17	$0.21	2.11%	0.06%
Delivery (includes Distribution)			**$95.22**			**$103.31**	**$8.09**	**8.50%**	**2.46%**
Cost of Power Commodity (kWh)	750	$0.0570	$42.75	750	$0.0570	$42.75			
Cost of Power Commodity (kWh)	2,361	0.0660	$155.83	2,428	0.0660	$160.25	$4.42	2.84%	1.34%
Wholesale Market Service (kWh)	3,111	0.0065	$20.22	3,178	0.0065	$20.66	$0.44	2.18%	0.13%
Debt retirement charge (kWh)	3,000	0.0049	$14.70	3,000	0.0049	$14.70			
Cost of Power / WMS / DRC			**$233.50**			**$238.36**	**$4.86**	**2.08%**	**1.48%**
Total Bill			**$328.72**			**$341.67**	**$12.95**	**3.94%**	**3.94%**

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
5,000 kWh	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**Rate Change Impact $**	**Change %**	**As a % of 2009 Total Bill**
Monthly Service Charge			$30.79			$35.56	$4.77	15.49%	0.90%
Distribution (kWh)	5,000	$0.0144	$72.00	5,000	$0.0164	$82.12	$10.12	14.06%	1.91%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	5,000			5,000	($0.0011)	($5.30)	($5.30)		-1.00%
Distribution			**$103.79**			**$113.38**	**$9.59**	**9.24%**	**1.81%**
RTSR Network (kWh)	5,185	0.0033	$17.11	5,297	0.0033	$17.48	$0.37	2.16%	0.07%
RTSR Connection (kWh)	5,185	0.0032	$16.59	5,297	0.0032	$16.95	$0.36	2.17%	0.07%
Delivery (includes Distribution)			**$137.49**			**$147.81**	**$10.32**	**7.51%**	**1.94%**
Cost of Power Commodity (kWh)	750	$0.0570	$42.75	750	$0.0570	$42.75			
Cost of Power Commodity (kWh)	4,435	0.0660	$292.71	4,547	0.0660	$300.10	$7.39	2.52%	1.39%
Wholesale Market Service (kWh)	5,185	0.0065	$33.70	5,297	0.0065	$34.43	$0.73	2.17%	0.14%
Debt retirement charge (kWh)	5,000	0.0049	$24.50	5,000	0.0049	$24.50			
Cost of Power / WMS / DRC			**$393.66**			**$401.78**	**$8.12**	**2.06%**	**1.53%**
Total Bill			**$531.15**			**$549.59**	**$18.44**	**3.47%**	**3.47%**

GENERAL SERVICE LESS THAN 50 KW Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
10,000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$30.79			$35.56	$4.77	15.49%	0.46%
Distribution (kWh)	10,000	$0.0144	$144.00	10,000	$0.0164	$164.25	$20.25	14.06%	1.95%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	10,000			10,000	($0.0011)	($10.60)	($10.60)		-1.02%
Distribution			**$175.79**			**$190.21**	**$14.42**	**8.20%**	**1.39%**
RTSR Network (kWh)	10,370	0.0033	$34.22	10,593	0.0033	$34.96	$0.74	2.16%	0.07%
RTSR Connection (kWh)	10,370	0.0032	$33.18	10,593	0.0032	$33.90	$0.72	2.17%	0.07%
Delivery (includes Distribution)			**$243.19**			**$259.07**	**$15.88**	**6.53%**	**1.53%**
Cost of Power Commodity (kWh)	750	$0.0570	$42.75	750	$0.0570	$42.75			
Cost of Power Commodity (kWh)	9,620	0.0660	$634.92	9,843	0.0660	$649.64	$14.72	2.32%	1.42%
Wholesale Market Service (kWh)	10,370	0.0065	$67.41	10,593	0.0065	$68.85	$1.44	2.14%	0.14%
Debt retirement charge (kWh)	10,000	0.0049	$49.00	10,000	0.0049	$49.00			
Cost of Power / WMS / DRC			**$794.08**			**$810.24**	**$16.16**	**2.04%**	**1.56%**
Total Bill			**$1,037.27**			**$1,069.31**	**$32.04**	**3.09%**	**3.09%**

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
15,000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$30.79			$35.56	$4.77	15.49%	0.31%
Distribution (kWh)	15,000	$0.0144	$216.00	15,000	$0.0164	$246.37	$30.37	14.06%	1.97%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	15,000			15,000	($0.0011)	($15.91)	($15.91)		-1.03%
Distribution			**$247.79**			**$267.02**	**$19.23**	**7.76%**	**1.25%**
RTSR Network (kWh)	15,555	0.0033	$51.33	15,890	0.0033	$52.44	$1.11	2.16%	0.07%
RTSR Connection (kWh)	15,555	0.0032	$49.78	15,890	0.0032	$50.85	$1.07	2.15%	0.07%
Delivery (includes Distribution)			**$348.90**			**$370.31**	**$21.41**	**6.14%**	**1.39%**
Cost of Power Commodity (kWh)	750	$0.0570	$42.75	750	$0.0570	$42.75			
Cost of Power Commodity (kWh)	14,805	0.0660	$977.13	15,140	0.0660	$999.24	$22.11	2.26%	1.43%
Wholesale Market Service (kWh)	15,555	0.0065	$101.11	15,890	0.0065	$103.29	$2.18	2.16%	0.14%
Debt retirement charge (kWh)	15,000	0.0049	$73.50	15,000	0.0049	$73.50			
Cost of Power / WMS / DRC			**$1,194.49**			**$1,218.78**	**$24.29**	**2.03%**	**1.57%**
Total Bill			**$1,543.39**			**$1,589.09**	**$45.70**	**2.96%**	**2.96%**

GENERAL SERVICE LESS THAN 50 KW Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption	BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
20,000 kWh	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge			$30.79			$35.56	$4.77	15.49%	0.23%
Distribution (kWh)	20,000	$0.0144	$288.00	20,000	$0.0164	$328.50	$40.50	14.06%	1.98%
Smart Meter Rider (per month)			$1.00			$1.00			
Reg Asset Rider (kWh)	20,000			20,000	($0.0011)	($21.21)	($21.21)		-1.03%
Distribution			**$319.79**			**$343.85**	**$24.06**	**7.52%**	**1.17%**
RTSR Network (kWh)	20,740	0.0033	$68.44	21,186	0.0033	$69.91	$1.47	2.15%	0.07%
RTSR Connection (kWh)	20,740	0.0032	$66.37	21,186	0.0032	$67.80	$1.43	2.15%	0.07%
Delivery (includes Distribution)			**$454.60**			**$481.56**	**$26.96**	**5.93%**	**1.32%**
Cost of Power Commodity (kWh)	750	$0.0570	$42.75	750	$0.0570	$42.75			
Cost of Power Commodity (kWh)	19,990	0.0660	$1,319.34	20,436	0.0660	$1,348.78	$29.44	2.23%	1.44%
Wholesale Market Service (kWh)	20,740	0.0065	$134.81	21,186	0.0065	$137.71	$2.90	2.15%	0.14%
Debt retirement charge (kWh)	20,000	0.0049	$98.00	20,000	0.0049	$98.00			
Cost of Power / WMS / DRC			**$1,594.90**			**$1,627.24**	**$32.34**	**2.03%**	**1.58%**
Total Bill			**$2,049.50**			**$2,108.80**	**$59.30**	**2.89%**	**2.89%**

GENERAL SERVICE 50 KW OR GREATER Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption kWh & kW		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
24,000	**60**	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$338.04			$375.23	$37.19	11.00%	1.58%
Distribution (kW)		60	$3.4023	$204.14	60	$3.6521	$219.12	$14.98	7.34%	0.64%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kW)		60			60	($0.5841)	($35.05)	($35.05)		-1.49%
Distribution				**$543.18**			**$560.30**	**$17.12**	**3.15%**	**0.73%**
RTSR Network (kW)		60	1.4236	$85.42	60	1.4236	$85.42			
RTSR Connection (kW)		60	1.2955	$77.73	60	1.2955	$77.73			
Delivery (includes Distribution)				**$706.33**			**$723.45**	**$17.12**	**2.42%**	**0.73%**
Wholesale Market Service (kWh)		24,888	0.0065	$161.77	25,423	0.0065	$165.25	$3.48	2.15%	0.15%
Cost of Power Commodity (kWh)		24,888	0.0550	$1,368.84	25,423	0.0550	$1,398.28	$29.44	2.15%	1.25%
Debt retirement charge (kWh)		24,000	0.0049	$117.60	24,000	0.0049	$117.60			
Cost of Power / WMS / DRC				**$1,648.21**			**$1,681.13**	**$32.92**	**2.00%**	**1.40%**
Total Bill				**$2,354.54**			**$2,404.58**	**$50.04**	**2.13%**	**2.13%**

Consumption kWh & kW		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
40,000	**100**	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$338.04			$375.23	$37.19	11.00%	1.01%
Distribution (kW)		100	$3.4023	$340.23	100	$3.6521	$365.21	$24.98	7.34%	0.68%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kW)		100			100	($0.5841)	($58.41)	($58.41)		-1.58%
Distribution				**$679.27**			**$683.03**	**$3.76**	**0.55%**	**0.10%**
RTSR Network (kW)		100	1.4236	$142.36	100	1.4236	$142.36			
RTSR Connection (kW)		100	1.2955	$129.55	100	1.2955	$129.55			
Delivery (includes Distribution)				**$951.18**			**$954.94**	**$3.76**	**0.40%**	**0.10%**
Wholesale Market Service (kWh)		41,480	0.0065	$269.62	42,372	0.0065	$275.42	$5.80	2.15%	0.16%
Cost of Power Commodity (kWh)		41,480	0.0550	$2,281.40	42,372	0.0550	$2,330.46	$49.06	2.15%	1.33%
Debt retirement charge (kWh)		40,000	0.0049	$196.00	40,000	0.0049	$196.00			
Cost of Power / WMS / DRC				**$2,747.02**			**$2,801.88**	**$54.86**	**2.00%**	**1.48%**
Total Bill				**$3,698.20**			**$3,756.82**	**$58.62**	**1.59%**	**1.59%**

GENERAL SERVICE 50 KW OR GREATER Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption kWh & kW		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
200,000	**500**	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$338.04			$375.23	$37.19	11.00%	0.22%
Distribution (kW)		500	$3.4023	$1,701.15	500	$3.6521	$1,826.03	$124.88	7.34%	0.73%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kW)		500			500	($0.5841)	($292.06)	($292.06)		-1.70%
Distribution				**$2,040.19**			**$1,910.20**	**($129.99)**	**-6.37%**	**-0.76%**
RTSR Network (kW)		500	1.4236	$711.80	500	1.4236	$711.80			
RTSR Connection (kW)		500	1.2955	$647.75	500	1.2955	$647.75			
Delivery (includes Distribution)				**$3,399.74**			**$3,269.75**	**($129.99)**	**-3.82%**	**-0.76%**
Wholesale Market Service (kWh)		207,400	0.0065	$1,348.10	211,860	0.0065	$1,377.09	$28.99	2.15%	0.17%
Cost of Power Commodity (kWh)		207,400	0.0550	$11,407.00	211,860	0.0550	$11,652.30	$245.30	2.15%	1.43%
Debt retirement charge (kWh)		200,000	0.0049	$980.00	200,000	0.0049	$980.00			
Cost of Power / WMS / DRC				**$13,735.10**			**$14,009.39**	**$274.29**	**2.00%**	**1.60%**
Total Bill				**$17,134.84**			**$17,279.14**	**$144.30**	**0.84%**	**0.84%**

Consumption kWh & kW		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
400,000	**1,000**	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$338.04			$375.23	$37.19	11.00%	0.11%
Distribution (kW)		1,000	$3.4023	$3,402.30	1,000	$3.6521	$3,652.07	$249.77	7.34%	0.74%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kW)		1,000			1,000	($0.5841)	($584.12)	($584.12)		-1.72%
Distribution				**$3,741.34**			**$3,444.18**	**($297.16)**	**-7.94%**	**-0.88%**
RTSR Network (kW)		1,000	1.4236	$1,423.60	1,000	1.4236	$1,423.60			
RTSR Connection (kW)		1,000	1.2955	$1,295.50	1,000	1.2955	$1,295.50			
Delivery (includes Distribution)				**$6,460.44**			**$6,163.28**	**($297.16)**	**-4.60%**	**-0.88%**
Wholesale Market Service (kWh)		414,800	0.0065	$2,696.20	423,720	0.0065	$2,754.18	$57.98	2.15%	0.17%
Cost of Power Commodity (kWh)		414,800	0.0550	$22,814.00	423,720	0.0550	$23,304.60	$490.60	2.15%	1.45%
Debt retirement charge (kWh)		400,000	0.0049	$1,960.00	400,000	0.0049	$1,960.00			
Cost of Power / WMS / DRC				**$27,470.20**			**$28,018.78**	**$548.58**	**2.00%**	**1.62%**
Total Bill				**$33,930.64**			**$34,182.06**	**$251.42**	**0.74%**	**0.74%**

GENERAL SERVICE 50 KW OR GREATER Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption kWh & kW		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
1,000,000	2,500	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$338.04			$375.23	$37.19	11.00%	0.04%
Distribution (kW)		2,500	$3.4023	$8,505.75	2,500	$3.6521	$9,130.17	$624.42	7.34%	0.74%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kW)		2,500			2,500	($0.5841)	($1,460.30)	($1,460.30)		-1.73%
Distribution				**$8,844.79**			**$8,046.10**	**($798.69)**	**-9.03%**	**-0.95%**
RTSR Network (kW)		2,500	1.4236	$3,559.00	2,500	1.4236	$3,559.00			
RTSR Connection (kW)		2,500	1.2955	$3,238.75	2,500	1.2955	$3,238.75			
Delivery (includes Distribution)				**$15,642.54**			**$14,843.85**	**($798.69)**	**-5.11%**	**-0.95%**
Wholesale Market Service (kWh)		1,037,000	0.0065	$6,740.50	1,059,300	0.0065	$6,885.45	$144.95	2.15%	0.17%
Cost of Power Commodity (kWh)		1,037,000	0.0550	$57,035.00	1,059,300	0.0550	$58,261.50	$1,226.50	2.15%	1.45%
Debt retirement charge (kWh)		1,000,000	0.0049	$4,900.00	1,000,000	0.0049	$4,900.00			
Cost of Power / WMS / DRC				**$68,675.50**			**$70,046.95**	**$1,371.45**	**2.00%**	**1.63%**
Total Bill				**$84,318.04**			**$84,890.80**	**$572.76**	**0.68%**	**0.68%**

Consumption kWh & kW		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
1,250,000	3,100	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$338.04			$375.23	$37.19	11.00%	0.04%
Distribution (kW)		3,100	$3.4023	$10,547.13	3,100	$3.6521	$11,321.42	$774.29	7.34%	0.74%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kW)		3,100			3,100	($0.5841)	($1,810.77)	($1,810.77)		-1.72%
Distribution				**$10,886.17**			**$9,886.88**	**($999.29)**	**-9.18%**	**-0.95%**
RTSR Network (kW)		3,100	1.4236	$4,413.16	3,100	1.4236	$4,413.16			
RTSR Connection (kW)		3,100	1.2955	$4,016.05	3,100	1.2955	$4,016.05			
Delivery (includes Distribution)				**$19,315.38**			**$18,316.09**	**($999.29)**	**-5.17%**	**-0.95%**
Wholesale Market Service (kWh)		1,296,250	0.0065	$8,425.63	1,324,125	0.0065	$8,606.81	$181.18	2.15%	0.17%
Cost of Power Commodity (kWh)		1,296,250	0.0550	$71,293.75	1,324,125	0.0550	$72,826.88	$1,533.13	2.15%	1.46%
Debt retirement charge (kWh)		1,250,000	0.0049	$6,125.00	1,250,000	0.0049	$6,125.00			
Cost of Power / WMS / DRC				**$85,844.38**			**$87,558.69**	**$1,714.31**	**2.00%**	**1.63%**
Total Bill				**$105,159.76**			**$105,874.78**	**$715.02**	**0.68%**	**0.68%**

GENERAL SERVICE 50 KW OR GREATER Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

Consumption kWh & kW		BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
1,600,000	4,000	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Service Charge				$338.04			$375.23	$37.19	11.00%	0.03%
Distribution (kW)		4,000	$3.4023	$13,609.20	4,000	$3.6521	$14,608.28	$999.08	7.34%	0.74%
Smart Meter Rider (per month)				$1.00			$1.00			
Reg Asset Rider (kW)		4,000			4,000	($0.5841)	($2,336.47)	($2,336.47)		-1.73%
Distribution				**$13,948.24**			**$12,648.04**	**($1,300.20)**	**-9.32%**	**-0.97%**
RTSR Network (kW)		4,000	1.4236	$5,694.40	4,000	1.4236	$5,694.40			
RTSR Connection (kW)		4,000	1.2955	$5,182.00	4,000	1.2955	$5,182.00			
Delivery (includes Distribution)				**$24,824.64**			**$23,524.44**	**($1,300.20)**	**-5.24%**	**-0.97%**
Wholesale Market Service (kWh)		1,659,200	0.0065	$10,784.80	1,694,880	0.0065	$11,016.72	$231.92	2.15%	0.17%
Cost of Power Commodity (kWh)		1,659,200	0.0550	$91,256.00	1,694,880	0.0550	$93,218.40	$1,962.40	2.15%	1.46%
Debt retirement charge (kWh)		1,600,000	0.0049	$7,840.00	1,600,000	0.0049	$7,840.00			
Cost of Power / WMS / DRC				**$109,880.80**			**$112,075.12**	**$2,194.32**	**2.00%**	**1.63%**
Total Bill				**$134,705.44**			**$135,599.56**	**$894.12**	**0.66%**	**0.66%**

STREET LIGHTING Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

kWh & kW & Connections			BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
193,000	520	3,200	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Connection Charge			3,200	$1.0600	$3,392.00	3,200	$2.7700	$8,864.00	$5,472.00	161.32%	27.88%
Reg Asset Rider (kW)			520			520	($0.2590)	($134.69)	($134.69)		-0.69%
Distribution (kW)			520	$3.7225	$1,935.70	520	$9.3556	$4,864.92	$2,929.22	151.33%	14.92%
Distribution					**$5,327.70**			**$13,594.23**	**$8,266.53**	**155.16%**	**42.11%**
RTSR Network (kW)			520	1.0487	$545.32	520	1.0487	$545.32			
RTSR Connection (kW)			520	0.9659	$502.27	520	0.9659	$502.27			
Delivery (includes Distribution)					**$6,375.29**			**$14,641.82**	**$8,266.53**	**129.67%**	**42.11%**
Cost of Power Commodity (kWh)			200,141	0.0550	$11,007.76	204,445	0.0550	$11,244.48	$236.72	2.15%	1.21%
Wholesale Market Service (kWh)			200,141	0.0065	$1,300.92	204,445	0.0065	$1,328.89	$27.97	2.15%	0.14%
Debt retirement charge (kWh)			193,000	0.0049	$945.70	193,000	0.0049	$945.70			
Cost of Power / WMS / DRC					**$13,254.38**			**$13,519.07**	**$264.69**	**2.00%**	**1.35%**
Total Bill					**$19,629.67**			**$28,160.89**	**$8,531.22**	**43.46%**	**43.46%**

kWh & kW & Connections			BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
205,000	560	3,400	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Connection Charge			3,400	$1.0600	$3,604.00	3,400	$2.7700	$9,418.00	$5,814.00	161.32%	27.82%
Reg Asset Rider (kW)			560			560	($0.2590)	($145.05)	($145.05)		-0.69%
Distribution (kW)			560	$3.7225	$2,084.60	560	$9.3556	$5,239.14	$3,154.54	151.33%	15.10%
Distribution					**$5,688.60**			**$14,512.09**	**$8,823.49**	**155.11%**	**42.23%**
RTSR Network (kW)			560	1.0487	$587.27	560	1.0487	$587.27			
RTSR Connection (kW)			560	0.9659	$540.90	560	0.9659	$540.90			
Delivery (includes Distribution)					**$6,816.77**			**$15,640.26**	**$8,823.49**	**129.44%**	**42.23%**
Cost of Power Commodity (kWh)			212,585	0.0550	$11,692.18	217,157	0.0550	$11,943.64	$251.46	2.15%	1.20%
Wholesale Market Service (kWh)			212,585	0.0065	$1,381.80	217,157	0.0065	$1,411.52	$29.72	2.15%	0.14%
Debt retirement charge (kWh)			205,000	0.0049	$1,004.50	205,000	0.0049	$1,004.50			
Cost of Power / WMS / DRC					**$14,078.48**			**$14,359.66**	**$281.18**	**2.00%**	**1.35%**
Total Bill					**$20,895.25**			**$29,999.92**	**$9,104.67**	**43.57%**	**43.57%**

STREET LIGHTING Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

kWh & kW & Connections			BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
217,000	590	3,600	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Connection Charge			3,600	$1.0600	$3,816.00	3,600	$2.7700	$9,972.00	$6,156.00	161.32%	27.85%
Reg Asset Rider (kW)			590			590	($0.2590)	($152.82)	($152.82)		-0.69%
Distribution (kW)			590	$3.7225	$2,196.28	590	$9.3556	$5,519.81	$3,323.53	151.33%	15.04%
Distribution					**$6,012.28**			**$15,338.99**	**$9,326.71**	**155.13%**	**42.20%**
RTSR Network (kW)			590	1.0487	$618.73	590	1.0487	$618.73			
RTSR Connection (kW)			590	0.9659	$569.88	590	0.9659	$569.88			
Delivery (includes Distribution)					**$7,200.89**			**$16,527.60**	**$9,326.71**	**129.52%**	**42.20%**
Cost of Power Commodity (kWh)			225,029	0.0550	$12,376.60	229,868	0.0550	$12,642.74	$266.14	2.15%	1.20%
Wholesale Market Service (kWh)			225,029	0.0065	$1,462.69	229,868	0.0065	$1,494.14	$31.45	2.15%	0.14%
Debt retirement charge (kWh)			217,000	0.0049	$1,063.30	217,000	0.0049	$1,063.30			
Cost of Power / WMS / DRC					**$14,902.59**			**$15,200.18**	**$297.59**	**2.00%**	**1.35%**
Total Bill					**$22,103.48**			**$31,727.78**	**$9,624.30**	**43.54%**	**43.54%**

kWh & kW & Connections			BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
229,000	620	3,800	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Connection Charge			3,800	$1.0600	$4,028.00	3,800	$2.7700	$10,526.00	$6,498.00	161.32%	27.87%
Reg Asset Rider (kW)			620			620	($0.2590)	($160.59)	($160.59)		-0.69%
Distribution (kW)			620	$3.7225	$2,307.95	620	$9.3556	$5,800.48	$3,492.53	151.33%	14.98%
Distribution					**$6,335.95**			**$16,165.89**	**$9,829.94**	**155.15%**	**42.17%**
RTSR Network (kW)			620	1.0487	$650.19	620	1.0487	$650.19			
RTSR Connection (kW)			620	0.9659	$598.86	620	0.9659	$598.86			
Delivery (includes Distribution)					**$7,585.00**			**$17,414.94**	**$9,829.94**	**129.60%**	**42.17%**
Cost of Power Commodity (kWh)			237,473	0.0550	$13,061.02	242,580	0.0550	$13,341.90	$280.88	2.15%	1.20%
Wholesale Market Service (kWh)			237,473	0.0065	$1,543.57	242,580	0.0065	$1,576.77	$33.20	2.15%	0.14%
Debt retirement charge (kWh)			229,000	0.0049	$1,122.10	229,000	0.0049	$1,122.10			
Cost of Power / WMS / DRC					**$15,726.69**			**$16,040.77**	**$314.08**	**2.00%**	**1.35%**
Total Bill					**$23,311.69**			**$33,455.71**	**$10,144.02**	**43.51%**	**43.51%**

STREET LIGHTING Monthly Bill Impact Calculations - Change From May 1, 2009 Approved to May 1, 2010 Proposed Rates

kWh & kW & Connections			BILL May 1, 2009 Current Rates			BILL May 1, 2010 Proposed Rates			RATE CHANGE IMPACTS		
241,000	660	4,000	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Rate Change Impact $	Change %	As a % of 2009 Total Bill
Monthly Connection Charge			4,000	$1.0600	$4,240.00	4,000	$2.7700	$11,080.00	$6,840.00	161.32%	27.83%
Reg Asset Rider (kW)			660			660	($0.2590)	($170.95)	($170.95)		-0.70%
Distribution (kW)			660	$3.7225	$2,456.85	660	$9.3556	$6,174.70	$3,717.85	151.33%	15.13%
Distribution					**$6,696.85**			**$17,083.75**	**$10,386.90**	**155.10%**	**42.26%**
RTSR Network (kW)			660	1.0487	$692.14	660	1.0487	$692.14			
RTSR Connection (kW)			660	0.9659	$637.49	660	0.9659	$637.49			
Delivery (includes Distribution)					**$8,026.48**			**$18,413.38**	**$10,386.90**	**129.41%**	**42.26%**
Cost of Power Commodity (kWh)			249,917	0.0550	$13,745.44	255,291	0.0550	$14,041.01	$295.57	2.15%	1.20%
Wholesale Market Service (kWh)			249,917	0.0065	$1,624.46	255,291	0.0065	$1,659.39	$34.93	2.15%	0.14%
Debt retirement charge (kWh)			241,000	0.0049	$1,180.90	241,000	0.0049	$1,180.90			
Cost of Power / WMS / DRC					**$16,550.80**			**$16,881.30**	**$330.50**	**2.00%**	**1.34%**
Total Bill					**$24,577.28**			**$35,294.68**	**$10,717.40**	**43.61%**	**43.61%**

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS

Schedule No.

EXHIBIT 9 - TABLES

EXHIBIT 9 - APPENDICES

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

The following is a list of all outstanding deferral and variance accounts used by OPDC as at December 31, 2008 including interest. The description of these accounts is consistent with the Accounting Procedures Handbook (APH).

Table 9-1: List of Outstanding Deferral and Variance Accounts as at Dec 31, 2008

Description	Acct #	Amount
RSVA - Wholesale Market Service Charge	1580	($2,559,972)
RSVA - One-time Wholesale Market Service	1582	$0
RSVA - Retail Transmission Network Charge	1584	($636,441)
RSVA - Retail Transmission Connection Charge	1586	($659,231)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$69,034
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$199,615
Retail Cost Variance Account - Retail	1518	($86,279)
Retail Cost Variance Account - STR	1548	$14,140
LV Variance Account	1550	$529,109
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$32,915
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	($115,766)
Conservation and Demand Management Expenditures and Recoveries	1565	$5
CDM Contra	1566	$45
RSVA - Power (including Global Adjustment)	1588	$2,713,515
Recovery of Regulatory Asset Balances	1590	($29,278)
Total		**($528,589)**

OPDC's continuity schedule for the period January 1, 2005 to December 31, 2008, showing separate itemization of opening balances, annual adjustments, accruals, interest and closing balances is included in excel spreadsheet in Appendix 9-A.

The interest rates applied to calculate the carrying charges for each regulatory deferral and variance account are shown in Table 9-2 by quarter.

Table 9-2: Prescribed Interest Rates for Carrying Charges

Year	Q 1	Q 2	Q 3	Q 4
2005	0.0725	0.0725	0.0725	0.0725
2006	0.0725	0.0414	0.0459	0.0459
2007	0.0459	0.0459	0.0459	0.0514
2008	0.0514	0.0408	0.0335	0.0335
2009	0.0245	0.0100	0.0055	

Information provided in continuity schedule is consistent with the data included in the trial balance reported through the Electricity Reporting and Record Keeping Requirements (RRR). OPDC plans to continue using the above accounts on a going forward basis. OPDC is not requesting any new accounts at this time.

Global Adjustment sub account:

With regards to the Account 1588 Power – Sub-Account Global Adjustment the variance in this account is based on the difference settled with the IESO and the provincial benefit settled with customers. The drivers generating the variance in Account 1588 Power Sub-account Global Adjustment are the rates prescribed by the IESO on purchases of power from the IESO and on distributor billing. The timing difference between distributor costs (paid within 15 days) and billings (collected up to 75 days later) impacts the balance in this account reported quarterly. The balance on the continuity schedule is $198,005 at Dec 31/08 ($192,474 plus carrying charges of $5,531). Approximately 72.2% of this amount is related to general service 50 kW and greater accounts, 21.1% is residential with the balance related to the small general service class.

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

The following are the accounts and the balance for which OPDC is seeking disposition of in this application along with the method used to allocate the balance to rate classes for disposition.

Table 9-3: Deferral and Variance Accounts Seeking Dispostion

Description	Acct #	Amount to Dec 31, 2008	Interest to May 1, 2010	Total Claim	Allocation to Rate Class Method
Balance as at Dec 31, 2008 Plus Interest to May 1, 2010					
RSVA - Wholesale Market Service Charge	1580	($2,559,972)	($36,634)	($2,596,606)	2008 kWh
RSVA - Retail Transmission Network Charge	1584	($636,441)	($8,667)	($645,108)	2008 kWh
RSVA - Retail Transmission Connection Charge	1586	($659,231)	($9,052)	($668,283)	2008 kWh
RSVA - Power	1588	$2,713,515	$35,615	$2,749,130	2008 kWh
Other Regulatory Assets	1508	$268,649	$3,569	$272,218	2008 Dx Rev
Retail Cost Variance Account - Retail	1518	($86,279)	($1,206)	($87,485)	2008 Cust
Retail Cost Variance Account - STR	1548	$14,140	$201	$14,341	2008 Cust
Low Voltage	1550	$529,109	$7,672	$536,781	2008 kWh
Total		**($416,510)**	**($8,502)**	**($425,012)**	

Table 9-4 shown below provides the following:

a) the proposed rate for recovery of balances that are proposed for clearance;

b) the proposed rate riders that assume recovery of all deferral and variance accounts as of the date of the last Audited Financial Statements and;

c) the proposed rate riders that assume recovery of all non-RSVA variance accounts as of the date of the last Audited Financial Statements.

OPDC is proposing to dispose of the deferral and variance accounts over a one year period. The details of the calculations of the proposed rate riders has been included in the excel spreadsheet under Appendix 9-B.

Table 9-4: Regulatory Asset Recovery Rate Riders

	Non-RSVA only		RSVA only		ALL Accounts (excl. 1555)	
Class	per kWh	per kW	per kWh	per kW	per kWh	per kW
Residential	$0.0024		($0.0036)		($0.0013)	
GS<50 kW	$0.0026		($0.0036)		($0.0011)	
GS>50 kW		$0.8553		($1.4394)		($0.5841)
Street Lighting		$1.0512		($1.3102)		($0.2590)
Sentinel		$0.7800		($1.3118)		($0.5318)
Unmetered Scattered Load	$0.0035		($0.0036)		($0.0001)	

OPDC is not proposing the clearance of account 1590 at this time. It is our understanding that the Board will typically not dispose of this account until such time as the final balance can be verified.

SMART METERS

OPDC is not requesting clearance of the smart meter variance accounts at this time. OPDC is proposing to continue using the current approved smart meter adder of $1.00 per meter per month for 2010 rates. OPDC's schedule for deployment of smart meters is the fall of 2009. Once smart meters are fully deployed and all costs are in, OPDC 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.

APPENDIX 9-A

The next 5 pages represents OPDC's continuity schedule from 2005 to 2010 for deferral and variance accounts.

Appendix 9-A: Continuity Schedule for Deferral and Variance Accounts

Description	Acct #	2005 Jan 1 Opening Principal Amounts	2005 Additions excluding interest and adjustments	2005 Reductions excluding interest and adjustments	2005 Adjustments - instructed by Board	2005 Adjustments - other	2005 Dec 31 Closing Principal Balance
RSVA - Wholesale Market Service Charge	1580	144,134	17,565				**161,699**
RSVA - One-time Wholesale Market Service	1582	30,153					**$30,153**
RSVA - Retail Transmission Network Charge	1584	(1,130,506)	(379,969)			(66,035)	**($1,576,510)**
RSVA - Retail Transmission Connection Charge	1586	(1,105,744)	(355,598)			198,724	**($1,262,618)**
Other Reg Assets - OEB Cost Assessments	1508	37,995	56,266				**$94,261**
Other Reg Assets - Pension Contributions	1508		131,168				**$131,168**
Retail Cost Variance Account - Retail	1518	(35,597)		(14,703)			**($50,300)**
Retail Cost Variance Account - STR	1548	14,169	2,782	(253)			**$16,698**
Misc. Deferred Debits	1525	42,066				10,221	**$52,287**
LV Variance Account	1550						
Smart Meter Capital and Recovery Offset Varia	1555						
Smart Meter Capital and Recovery Offset Varia	1555						
Smart Meter Capital and Recovery Offset Varia	1555						
Smart Meter OM&A Variance	1556						
CDM Expenditures and Recoveries	1565	4,775	42,478	(172,500)			**($125,247)**
CDM Contra	1566		(47,253)	172,500			**$125,247**
Qualifying Transition Costs	1570	616,623	n/a	n/a	(61,662)	55	**$555,016**
Pre-Market Opening Energy Variance	1571	1,334,871	n/a	n/a			**$1,334,871**
RSVA - Power (including Global Adjustment)	1588	188,306	469,540				**$657,846**
Recovery of Reg Asset Balances	1590	(364,409)		(170,197)			**($534,606)**
Total		**($223,164)**	**($63,021)**	**($185,153)**	**($61,662)**	**$142,965**	**($390,035)**

Description	Acct #	2005 Jan 1 Opening Interest Amounts	2005 Interest Adjustment	2005 Dec 31 Closing Interest Amounts	2005 Dec 31 Combined Principal plus Interest Amts
RSVA - Wholesale Market Service Charge	1580	(25,016)	7,883	(17,133)	**144,566**
RSVA - One-time Wholesale Market Service	1582	1,968	2,185	4,153	**34,306**
RSVA - Retail Transmission Network Charge	1584	(64,395)	(76,520)	(140,915)	**(1,717,425)**
RSVA - Retail Transmission Connection Charge	1586	(62,022)	(61,739)	(123,761)	**(1,386,379)**
Other Reg Assets - OEB Cost Assessments	1508	546	3,465	4,011	**98,272**
Other Reg Assets - Pension Contributions	1508		2,227	2,227	**133,395**
Retail Cost Variance Account - Retail	1518	(2,386)	(3,100)	(5,486)	**(55,786)**
Retail Cost Variance Account - STR	1548	1,769	1,104	2,873	**19,571**
Misc. Deferred Debits	1525	5,816	3,606	9,422	**61,709**
LV Variance Account	1550				
Smart Meter Capital and Recovery Offset Varia	1555				
Smart Meter Capital and Recovery Offset Varia	1555				
Smart Meter Capital and Recovery Offset Varia	1555				
Smart Meter OM&A Variance	1556				
CDM Expenditures and Recoveries	1565	4	46	50	**(125,197)**
CDM Contra	1566				**125,247**
Qualifying Transition Costs	1570	95,472	30,690	126,162	**681,178**
Pre-Market Opening Energy Variance	1571	314,851	96,780	411,631	**1,746,502**
RSVA - Power (including Global Adjustment)	1588	42,300	92,896	135,196	**793,042**
Recovery of Reg Asset Balances	1590	(7,053)	(36,935)	(43,988)	**(578,594)**
Total		**$301,854**	**$62,588**	**$364,442**	**($25,593)**

Appendix 9-A: Continuity Schedule for Deferral and Variance Accounts

Description	Acct #	2006 Jan 1 Opening Principal Amounts	2006 Additions excluding interest and adjustments	2006 Reductions excluding interest and adjustments	2006 EDR Transfer of Board-apprvd amts to 1590	2006 Adjustments - other	2006 Dec 31 Closing Principal Balance
RSVA - Wholesale Market Service Charge	1580	161,699	(896,644)		(144,134)		**(879,079)**
RSVA - One-time Wholesale Market Service	1582	30,153			(30,153)		
RSVA - Retail Transmission Network Charge	1584	(1,576,510)	(190,067)		1,294,494	(97,953)	**(570,036)**
RSVA - Retail Transmission Connection Charge	1586	(1,262,618)	(189,969)		843,742	63,276	**(545,569)**
Other Reg Assets - OEB Cost Assessments	1508	94,261	5,075		(57,315)	18,292	**60,313**
Other Reg Assets - Pension Contributions	1508	131,168	43,849				**175,017**
Retail Cost Variance Account - Retail	1518	(50,300)		(20,358)	35,597		**(35,061)**
Retail Cost Variance Account - STR	1548	16,698	3,823	(1,660)	(14,170)		**4,691**
Misc. Deferred Debits	1525	52,287			(52,287)		
LV Variance Account	1550		259,828	(141,124)			**118,704**
Smart Meter Capital and Recovery Offset Varia	1555						
Smart Meter Capital and Recovery Offset Varia	1555			(27,603)			**(27,603)**
Smart Meter Capital and Recovery Offset Varia	1555						
Smart Meter OM&A Variance	1556						
CDM Expenditures and Recoveries	1565	(125,247)	111,416	(34,500)			**(48,331)**
CDM Contra	1566	125,247	(111,416)	34,500			**48,331**
Qualifying Transition Costs	1570	555,016	n/a	n/a	(555,016)		
Pre-Market Opening Energy Variance	1571	1,334,871	n/a	n/a	(1,334,871)		
RSVA - Power (including Global Adjustment)	1588	657,846	1,169,249		(188,306)		**1,638,789**
Recovery of Reg Asset Balances	1590	(534,606)	31,892		202,419		**(300,295)**
Total		**($390,035)**	**$237,036**	**($190,745)**		**($16,385)**	**($360,129)**

Description	Acct #	2006 Jan 1 Opening Interest Amounts	2006 Interest Adjustment	2006 EDR Transfer of Board-apprvd amts to 1590	2006 Dec 31 Closing Interest Amounts	2006 Dec 31 Combined Principal plus Interest Amts
RSVA - Wholesale Market Service Charge	1580	(17,133)	(9,795)	11,083	**(15,845)**	**(894,924)**
RSVA - One-time Wholesale Market Service	1582	4,153	729	(4,882)		
RSVA - Retail Transmission Network Charge	1584	(140,915)	(46,604)	178,864	**(8,655)**	**(578,691)**
RSVA - Retail Transmission Connection Charge	1586	(123,761)	(41,186)	153,302	**(11,645)**	**(557,214)**
Other Reg Assets - OEB Cost Assessments	1508	4,011	4,056	(4,219)	**3,848**	**64,161**
Other Reg Assets - Pension Contributions	1508	2,227	6,435		**8,662**	**183,679**
Retail Cost Variance Account - Retail	1518	(5,486)	(1,876)	5,827	**(1,535)**	**(36,596)**
Retail Cost Variance Account - STR	1548	2,873	415	(3,138)	**150**	**4,841**
Misc. Deferred Debits	1525	9,422	1,264	(10,686)		
LV Variance Account	1550		1,394		**1,394**	**120,098**
Smart Meter Capital and Recovery Offset Varia	1555					
Smart Meter Capital and Recovery Offset Varia	1555		(248)		**(248)**	**(27,851)**
Smart Meter Capital and Recovery Offset Varia	1555					
Smart Meter OM&A Variance	1556					
CDM Expenditures and Recoveries	1565	50			**50**	**(48,281)**
CDM Contra	1566					**48,331**
Qualifying Transition Costs	1570	126,162	13,407	(139,569)		
Pre-Market Opening Energy Variance	1571	411,631	32,257	(443,888)		
RSVA - Power (including Global Adjustment)	1588	135,196	80,962	(60,503)	**155,655**	**1,794,444**
Recovery of Reg Asset Balances	1590	(43,988)	(24,430)	317,809	**249,391**	**(50,904)**
Total		**$364,442**	**$16,780**		**$381,222**	**$21,093**

Appendix 9-A: Continuity Schedule for Deferral and Variance Accounts

Description	Acct #	2007 Jan 1 Opening Principal Amounts	2007 Additions excluding interest and adjustments	2007 Reductions excluding interest and adjustments	2007 Adjustments - instructed by Board	2007 Adjustments - other	2007 Dec 31 Closing Principal Balance
RSVA - Wholesale Market Service Charge	1580	(879,079)	(766,644)				**(1,645,723)**
RSVA - One-time Wholesale Market Service	1582						
RSVA - Retail Transmission Network Charge	1584	(570,036)	72,708				**(497,328)**
RSVA - Retail Transmission Connection Charge	1586	(545,569)	40,604				**(504,965)**
Other Reg Assets - OEB Cost Assessments	1508	60,313					**60,313**
Other Reg Assets - Pension Contributions	1508	175,017					**175,017**
Retail Cost Variance Account - Retail	1518	(35,061)		(23,636)			**(58,697)**
Retail Cost Variance Account - STR	1548	4,691	5,577	(1,726)			**8,542**
Misc. Deferred Debits	1525						
LV Variance Account	1550	118,704	422,516	(221,087)			**320,133**
Smart Meter Capital and Recovery Offset Varia	1555		16,479				**16,479**
Smart Meter Capital and Recovery Offset Varia	1555	(27,603)		(41,257)			**(68,860)**
Smart Meter Capital and Recovery Offset Varia	1555						
Smart Meter OM&A Variance	1556						
CDM Expenditures and Recoveries	1565	(48,331)	48,286				**(45)**
CDM Contra	1566	48,331	(48,286)				**45**
Qualifying Transition Costs	1570		n/a	n/a			
Pre-Market Opening Energy Variance	1571		n/a	n/a			
RSVA - Power (including Global Adjustment)	1588	1,638,789	194,951				**1,833,740**
Recovery of Reg Asset Balances	1590	(300,295)	39,232				**(261,063)**
Total		**($360,129)**	**$25,423**	**($287,706)**			**($622,412)**

Description	Acct #	2007 Jan 1 Opening Interest Amounts	2007 Interest Adjustment	2007 Dec 31 Closing Interest Amounts	2007 Dec 31 Combined Principal plus Interest Amts
RSVA - Wholesale Market Service Charge	1580	(15,845)	(53,526)	**(69,371)**	**(1,715,094)**
RSVA - One-time Wholesale Market Service	1582				
RSVA - Retail Transmission Network Charge	1584	(8,655)	(36,200)	**(44,855)**	**(542,183)**
RSVA - Retail Transmission Connection Charge	1586	(11,645)	(30,163)	**(41,808)**	**(546,773)**
Other Reg Assets - OEB Cost Assessments	1508	3,848	2,476	**6,324**	**66,637**
Other Reg Assets - Pension Contributions	1508	8,662	8,967	**17,629**	**192,646**
Retail Cost Variance Account - Retail	1518	(1,535)	(2,506)	**(4,041)**	**(62,738)**
Retail Cost Variance Account - STR	1548	150	359	**509**	**9,051**
Misc. Deferred Debits	1525				
LV Variance Account	1550	1,394	8,084	**9,478**	**329,611**
Smart Meter Capital and Recovery Offset Varia	1555				**16,479**
Smart Meter Capital and Recovery Offset Varia	1555	(248)	(2,171)	**(2,419)**	**(71,279)**
Smart Meter Capital and Recovery Offset Varia	1555				
Smart Meter OM&A Variance	1556				
CDM Expenditures and Recoveries	1565	50		**50**	**5**
CDM Contra	1566				**45**
Qualifying Transition Costs	1570				
Pre-Market Opening Energy Variance	1571				
RSVA - Power (including Global Adjustment)	1588	155,655	107,200	**262,855**	**2,096,595**
Recovery of Reg Asset Balances	1590	249,391	(12,167)	**237,224**	**(23,839)**
Total		**$381,222**	**($9,647)**	**$371,575**	**($250,837)**

Appendix 9-A: Continuity Schedule for Deferral and Variance Accounts

Description	Acct #	2008 Jan 1 Opening Principal Amounts	2008 Additions excluding interest and adjustments	2008 Reductions excluding interest and adjustments	2008 Adjustments - instructed by Board	2008 Adjustments - other	2008 Dec 31 Closing Principal Balance
RSVA - Wholesale Market Service Charge	1580	(1,645,723)	(769,677)				**(2,415,400)**
RSVA - One-time Wholesale Market Service	1582						
RSVA - Retail Transmission Network Charge	1584	(497,328)	(74,153)				**(571,481)**
RSVA - Retail Transmission Connection Charg	1586	(504,965)	(91,840)				**(596,805)**
Other Reg Assets - OEB Cost Assessments	1508	60,313					**60,313**
Other Reg Assets - Pension Contributions	1508	175,017					**175,017**
Retail Cost Variance Account - Retail	1518	(58,697)	(20,851)				**(79,548)**
Retail Cost Variance Account - STR	1548	8,542	4,693				**13,235**
Misc. Deferred Debits	1525						
LV Variance Account	1550	320,133	185,688				**505,821**
Smart Meter Capital and Recovery Offset Varia	1555	16,479	16,436				**32,915**
Smart Meter Capital and Recovery Offset Varia	1555	(68,860)	(41,887)				**(110,747)**
Smart Meter Capital and Recovery Offset Varia	1555						
Smart Meter OM&A Variance	1556						
CDM Expenditures and Recoveries	1565	(45)					**(45)**
CDM Contra	1566	45					**45**
Qualifying Transition Costs	1570		n/a	n/a			
Pre-Market Opening Energy Variance	1571		n/a	n/a			
RSVA - Power (including Global Adjustment)	1588	1,833,740	514,522				**2,348,262**
Recovery of Reg Asset Balances	1590	(261,063)	4,832				**(256,231)**
Total		**($622,412)**	**($272,237)**				**($894,649)**

Description	Acct #	2008 Jan 1 Opening Interest Amounts	2008 Interest Adjustment	2008 Dec 31 Closing Interest Amounts	2008 Dec 31 Combined Principal plus Interest Amts
RSVA - Wholesale Market Service Charge	1580	(69,371)	(75,201)	**(144,572)**	**(2,559,972)**
RSVA - One-time Wholesale Market Service	1582				
RSVA - Retail Transmission Network Charge	1584	(44,855)	(20,105)	**(64,960)**	**(636,441)**
RSVA - Retail Transmission Connection Charg	1586	(41,808)	(20,618)	**(62,426)**	**(659,231)**
Other Reg Assets - OEB Cost Assessments	1508	6,324	2,397	**8,721**	**69,034**
Other Reg Assets - Pension Contributions	1508	17,629	6,969	**24,598**	**199,615**
Retail Cost Variance Account - Retail	1518	(4,041)	(2,690)	**(6,731)**	**(86,279)**
Retail Cost Variance Account - STR	1548	509	396	**905**	**14,140**
Misc. Deferred Debits	1525				
LV Variance Account	1550	9,478	13,810	**23,288**	**529,109**
Smart Meter Capital and Recovery Offset Varia	1555				**32,915**
Smart Meter Capital and Recovery Offset Varia	1555	(2,419)	(2,600)	**(5,019)**	**(115,766)**
Smart Meter Capital and Recovery Offset Varia	1555				
Smart Meter OM&A Variance	1556				
CDM Expenditures and Recoveries	1565	50		**50**	**5**
CDM Contra	1566				**45**
Qualifying Transition Costs	1570				
Pre-Market Opening Energy Variance	1571				
RSVA - Power (including Global Adjustment)	1588	262,855	102,398	**365,253**	**2,713,515**
Recovery of Reg Asset Balances	1590	237,224	(10,271)	**226,953**	**(29,278)**
Total		**$371,575**	**($5,515)**	**$366,060**	**($528,589)**

Appendix 9-A: Continuity Schedule for Deferral and Variance Accounts

Description	Acct #	2008 Dec 31 Combined Principal plus Interest Amts	2009 Projected Interest for year	2010 Projected Interest to Apr 30	2010 Apr 30 Combined Principal plus Interest Amts
RSVA - Wholesale Market Service Charge	1580	**(2,559,972)**	(27,475)	(9,158)	**(2,596,606)**
RSVA - One-time Wholesale Market Service	1582				
RSVA - Retail Transmission Network Charge	1584	**(636,441)**	(6,501)	(2,167)	**(645,108)**
RSVA - Retail Transmission Connection Charg	1586	**(659,231)**	(6,789)	(2,263)	**(668,283)**
Other Reg Assets - OEB Cost Assessments	1508	**69,034**	686	229	**69,949**
Other Reg Assets - Pension Contributions	1508	**199,615**	1,991	664	**202,269**
Retail Cost Variance Account - Retail	1518	**(86,279)**	(905)	(302)	**(87,485)**
Retail Cost Variance Account - STR	1548	**14,140**	151	50	**14,341**
Misc. Deferred Debits	1525				
LV Variance Account	1550	**529,109**	5,754	1,918	**536,781**
Smart Meter Capital and Recovery Offset Varia	1555	**32,915**	374	125	**33,414**
Smart Meter Capital and Recovery Offset Varia	1555	**(115,766)**	(1,260)	(420)	**(117,445)**
Smart Meter Capital and Recovery Offset Varia	1555				
Smart Meter OM&A Variance	1556				
CDM Expenditures and Recoveries	1565	**5**	n/a	n/a	**5**
CDM Contra	1566	**45**	n/a	n/a	**45**
Qualifying Transition Costs	1570				
Pre-Market Opening Energy Variance	1571				
RSVA - Power (including Global Adjustment)	1588	**2,713,515**	26,711	8,904	**2,749,130**
Recovery of Reg Asset Balances	1590	**(29,278)**	(2,915)	(972)	**(33,164)**
Total		**($528,589)**	**($10,177)**	**($3,392)**	**($542,158)**

APPENDIX 9-B

The next 2 pages represent OPDC's calculation for rate riders for deferral and variance accounts being settled.

Appendix 9-B: Calculation of Rate Riders

Description	Acct #	Allocator	Amount Claimed
RSVA - Wholesale Market Service Charge	1580	kWh	**(2,596,606)**
RSVA - Retail Transmission Network Charge	1584	kWh	**(645,108)**
RSVA - Retail Transmission Connection Charge	1586	kWh	**(668,283)**
RSVA - Power (including Global Adjustment)	1588	kWh	**2,749,130**
Subtotal RSVA			**(1,160,867)**
Other Reg Assets - OEB Cost Assessments	1508	Dist Revenue	**69,949**
Other Reg Assets - Pension Contributions	1508	Dist Revenue	**202,269**
Retail Cost Variance Account - Retail	1518	Customers	**(87,485)**
Retail Cost Variance Account - STR	1548	Customers	**14,341**
LV Variance Account	1550	kWh	**536,781**
Subtotal NON RSVA			**735,855**
Total Amount For Rider Calculation			**($425,012)**

2008 Data By Class	kW	kWhs	Annualized Customers (Average)	Dx Revenue
RESIDENTIAL CLASS		109,814,584	134,172	$3,184,956
GENERAL SERVICE <50 KW CLASS		49,299,469	16,164	$1,188,923
GENERAL SERVICE >50 KW to 4,999 KW	394,737	156,139,234	1,860	$1,737,088
UNMETERED & SCATTERED LOADS		860,590	456	$41,507
SENTINEL LIGHTS	954	343,910	1,092	$15,702
STREET LIGHTING	7,083	2,550,182	12	$72,445
Totals	**402,774**	**319,007,969**	**153,756**	**$6,240,621**
RESIDENTIAL CLASS		34.4%	87.3%	51.0%
GENERAL SERVICE <50 KW CLASS		15.5%	10.5%	19.1%
GENERAL SERVICE >50 KW to 4,999 KW	98.0%	48.9%	1.2%	27.8%
UNMETERED & SCATTERED LOADS		0.3%	0.3%	0.7%
SENTINEL LIGHTS	0.2%	0.1%	0.7%	0.3%
STREET LIGHTING	1.8%	0.8%	0.0%	1.2%
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Appendix 9-B: Calculation of Rate Riders

Acct #	Allocator	Amount Claimed	Residential	GS < 50	GS > 50	Unmetered	Sentinel	Street Lights
1580	kWh	**(2,596,606)**	(893,850)	(401,279)	(1,270,915)	(7,005)	(2,799)	(20,758)
1584	kWh	**(645,108)**	(222,071)	(99,695)	(315,750)	(1,740)	(695)	(5,157)
1586	kWh	**(668,283)**	(230,048)	(103,276)	(327,093)	(1,803)	(720)	(5,342)
1588	kWh	**2,749,130**	946,354	424,850	1,345,568	7,416	2,964	21,977
Subtotal RSVA		**(1,160,867)**	**(399,614)**	**(179,400)**	**(568,189)**	**(3,132)**	**(1,251)**	**(9,280)**
1508	Dist Revenue	**69,949**	35,699	13,326	19,470	465	176	812
1508	Dist Revenue	**202,269**	103,230	38,535	56,302	1,345	509	2,348
1518	Customers	**(87,485)**	(76,342)	(9,197)	(1,058)	(259)	(621)	(7)
1548	Customers	**14,341**	12,514	1,508	173	43	102	1
1550	kWh	**536,781**	184,780	82,954	262,729	1,448	579	4,291
Subtotal NON RSVA		**735,855**	**259,881**	**127,126**	**337,616**	**3,042**	**744**	**7,445**
Totals For Rider Calc		**($425,012)**	**($139,733)**	**($52,274)**	**($230,573)**	**($90)**	**($507)**	**($1,835)**

RATE RIDERS	**kWh**	**kWh**	**kW**	**kWh**	**kW**	**kW**
Billing Determinant Used	**109,814,584**	**49,299,469**	**394,737**	**860,590**	**954**	**7,083**
RSVA	**(0.003639)**	**(0.003639)**	**(1.439412)**	**(0.003639)**	**(1.311830)**	**(1.310192)**
Non RSVA	**0.002367**	**0.002579**	**0.855294**	**0.003534**	**0.780009**	**1.051171**
RSVA and Non RSVA	**(0.0013)**	**(0.0011)**	**(0.5841)**	**(0.0001)**	**(0.5318)**	**(0.2590)**